ELECTRICITY DISTRIBUTION SERVICES 2022 PRICING METHODOLOGY

From 1 April 2021

Pursuant to:

The Electricity Distribution Information Disclosure Determination 2012 (Consolidated April 2018)

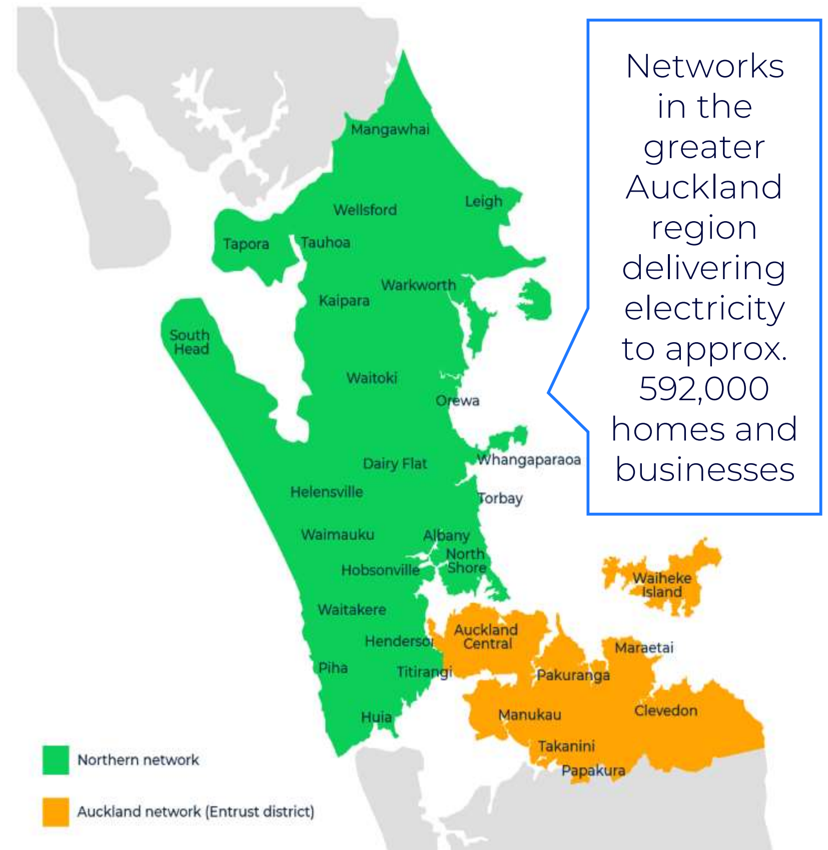
vector

EXECUTIVE SUMMARY

Vector ("our", "we", or "us") recovers the cost of owning and operating our electricity distribution networks (Network) through a combination of standard (published), non-standard prices for electricity distribution services, and capital contributions for new connections. We are regulated by the Commerce Commission (Commission) and are required to publish our pricing methodology for electricity distribution services (Pricing Methodology).

This document sets out our Pricing Methodology to meet the requirements of the Information Disclosure Determination 2012 (ID)[1]. It describes and explains the consumer groups, the price categories and components within each consumer group, how prices are set and the Cost of Service Model (COSM) allocation of target revenue to consumer groups. The ID requires price change commentary relating to the pricing strategy[2], but we do not currently have a pricing strategy as defined in the ID. We do however have a publicly available electricity pricing road map[3] that sets out how we are evolving on prices to enable and deliver better outcomes for consumers.

Figure 1: Our electricity distribution networks



- Prices are set to earn the level of revenue we are permitted to under the DPP, less any intentional under-pricing
- When setting prices we take into account - historical price structures, minimising rate shock to consumers, minimising recovery risk and ensuring that prices to individual consumer groups reflect their allocation of costs
- The impacts of Covid-19 are a key consideration for the current price setting cycle
- Forecast revenue increases must not exceed 10% in any one year. Pricing under the allowed revenue is permitted and can be recovered in future periods (adjusted for time value), we have under priced by a forecasted $19.1m
- Given network costs are largely fixed we typically apply any price increases to fixed components and price decreases to variable components. This means not all consumers will see the weighted average price change some will see more some less. We do though have discretion on the allocation approach applied providing it complies with pricing principles

[1] Electricity Distribution Information Disclosure Determination 2012 (consolidated April 2018), available at https://comcom.govt.nz/regulated-industries/electricity-lines/information-disclosure-requirements-for-electricity-distributors/current-information-disclosure-requirements-for-electricity-distributors

[2] A pricing strategy is a decision made by the Directors on the electricity distribution business' plans or strategy to amend or develop prices in the future, and recorded in writing

[3] Available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing under the heading "customer-led pricing design"

CONTENTS

1 – CONSUMER GROUPS

Consumer groups are determined on how they use the network and the nature of the network service they receive. These consumer groups are determined at a relatively high level, due to the physical nature of electricity distribution networks and the information that is available on consumer demand characteristics, as outlined below:

- There is a high degree of network meshing and interconnection of consumers;
- End consumers are not generally geographically segmented in their use of different network assets, for example, there are very few purely "industrial zones" or "residential zones"; and
- There is a mix of consumers, including a large number of consumers with relatively low individual consumption, and vice versa.

We have maintained the same five standard consumer groups as in the previous year, based on a measure of capacity connection and supply connection point type as shown in Table 1.

Table 1: Consumer groups

Consumer group and subgroup		Capacity connection	Supply connection
Mass market	➢ Residential ➢ General	Small ≤ 69kVA	Low voltage network
Unmetered	➢ General	Tiny ≤ 1kVA	Low voltage network
Low voltage	➢ Commercial	Large ≥ 69kVA	Low voltage network
Transformer	➢ Commercial	Large ≥ 69kVA	Vector owned transformer(s) which supplies consumer's Low Voltage network
High voltage	➢ Commercial	Large ≥ 69kVA	High voltage or sub-transmission (6.6kV or higher) network
Non-standard		Various	Various

Consumers on non-standard contracts which have met certain eligibility criteria, as outlined on page 11, are included in a separate consumer group.

Consumer groups are mutually exclusive so a consumer can only be in one group.

The mass market consumer group is split into two subgroups: residential and general with a key difference between the subgroups being that the Low User Regulations[4] apply only to the residential subgroup.

The unmetered consumer group is also in the general subgroup.

The low voltage, transformer and high voltage consumer groups are collectively referred to as commercial consumers.

[4] The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the Low User Regulations) require distributors to offer residential consumers a price option at their primary place of residence with a fixed price of no more than $0.15 per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option is no greater than any other residential price option for consumers using up to 8,000 kWh per annum

2 – PRICE CATEGORIES

Table 2 sets out the price categories[5] for consumers on our Auckland network (codes beginning with A) and our Northern network (beginning with W).

Table 2: Price categories

Consumer group and subgroup		Short description	Price category codes		Key eligibility criteria / purpose
			Auckland	Northern	
Mass market	Residential	Residential - time of use (TOU) - uncontrolled	ARHL ARHS	WRHL WRHS	Residential consumers without controllable load
		Residential - TOU - controlled	ARHLC ARHSC	WRHLC WRHSC	Residential consumers with controllable load or reticulated gas connections
		Residential - exemption - uncontrolled	ARUL ARUS	WRUL WRUS	Residential consumers with a Vector provided exemption from TOU price categories, and without controllable load or reticulated gas connections
		Residential - exemption - controlled	ARCL ARCS	WRCL WRCS	Residential consumers with a Vector provided exemption from TOU price categories, and with controllable load or reticulated gas connections
	General	General - TOU	ABSH	WBSH	Non-residential < 69kVA consumers
		General - exemption	ABSN	WBSN	Non-residential < 69kVA consumers with a Vector provided exemption from TOU price categories
Unmetered		General - unmetered	ABSU	WBSU	Unmetered < 1kVA capacity connections, mostly street lighting
Low voltage (LV)		LV- TOU	ALVT	WLVH	Main category for LV consumers, requires TOU metering
		LV- non TOU	ALVN	WLVN	For smaller LV consumers (< 345kVA) who may not have TOU metering
Transformer (TX)		TX - TOU	ATXT	WTXH	Main category for TX consumers, requires TOU metering
		TX - non TOU	ATXN	WTXN	For smaller TX consumers (< 345kVA) who may not have TOU metering
High voltage (HV)		HV - TOU	AHVT	WHVH	Main category for HV consumers, requires TOU metering
		HV - non TOU	AHVN	WHVN	For smaller HV consumers (< 345kVA) who may not have TOU metering

[5] Price categories are the relevant price plan (or tariff) from the price schedule that define the line prices applicable to a particular ICP. An ICP is an installation control point being a physical point of connection on a local network which a distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer

3 – PRICE COMPONENTS

We have a range of price components[6] that apply to different price categories depending on the characteristics of a particular category and the availability of metering data. Table 3 describes the various price components that we have. There are no changes from the previous year.

Table 3: Price components

Type	Component	Codes	Units	Description
Fixed	Daily	FIXD	$/day	Daily price applied to the number of days each consumer's point of connection (or fitting for unmetered connections) is energised
	Capacity	CAPY	$/kVA/day [7]	Daily price applied to the installed capacity (or nominated capacity for AHVT and WHVH) of each consumer
Variable	Volume	AICO, 24UC, OFPK, PEAK	$/kWh [8]	Volume price, applies to all electricity distributed to each consumer. Controlled volume (AICO), uncontrolled volume (24UC), off peak volume (OFPK), or peak volume (PEAK) (0700 to 1100 and 1700 to 2100 weekdays including public holidays)
	Demand	DAMD	$/kVA/day	Daily price applied to the average of the consumer's ten highest kVA demands between 8am and 8pm on weekdays each month
	Excess demand	DEXA	$/kVA/day	Daily price applied when the anytime maximum demand is greater than the nominated capacity and is applied to the difference between the anytime maximum kVA demand and the nominated capacity
	Power factor	PWRF	$/kVAr/day [9]	Daily price determined each month where a consumer's power factor is less than 0.95 lagging. The kVAr amount is calculated as twice the largest difference between the recorded kVArh[10] in any one half-hour period and the kWh demand recorded in the same period divided by three
	Injection	INJT	$/kWh	Volume injection price applies to all electricity injected into the network by each consumer

[6] Price components are the various prices that constitute the components of the total prices paid, or payable, by a consumer
[7] kVA is kilovolt–ampere (amp), a measure of apparent power being the product of volts and amps. Used for the measurement of capacity and demand for pricing
[8] kWh is kilowatt-hour, a unit of energy being the product of power in watts and time in hours. Used for the measurement of consumption for volumetric prices
[9] kVAr is kilovolt ampere reactive, is a unit used to measure reactive power in an AC electric power system. Used for the measurement of power factor in pricing
[10] kVArh is kilovolt ampere reactive hour, a unit of energy being the product of reactive power in kVAr and time in hours. Used for the measurement of power factor in pricing

4 – PRICING DEVELOPMENTS

The future is unpredictable. New business models are evolving in response to new consumer demands, new technologies and decarbonisation. We have taken the strategic decision to embrace these changes rather than resist them. We see this new environment as an opportunity to revise our pricing in response to an evolving market. We do not believe economically-principled, efficient pricing should be an end goal in and of itself.

Our consumer insights show that some consumers are interested in adopting new technology to manage their usage and save money while others prefer simplicity and convenience. Ultimately, we seek to implement pricing structures that meet consumer preferences, send the right signals and are well understood by consumers. Therefore, we are committed to continually evolve our prices to meet consumer expectations while still meeting regulatory requirements. This evolution includes consultations with consumers, retailers, industry experts and obtaining consumers insights through application of sophisticated data analytics.

Successful pricing reform will not be just about economics. Careful consideration of the trade-off between the extent of cost-reflectivity and the practical understanding of the price signal is paramount. Consideration is also needed of bill impacts resulting from moving to new pricing. This transition needs to be careful managed especially in regard to vulnerable consumers.

To assess the potential impacts of new line charge pricing models on consumers, it is essential that distributors have access to half-hourly consumer usage data at the ICP level. The current lack of access to this data is providing a barrier to the development and assessment of new pricing models. Retailers need to ensure that our pricing is passed through to our consumers. Re-packaging our tariffs risks obscuring the price signal and in turn preventing consumers from the potential benefits our pricing may afford.

It is worth highlighting that any substantial change to pricing structures creates challenges under the current regulatory framework in forecasting and allocating volumes for the purpose of weighting and setting prices. The Low User Regulations have introduced inefficiencies and inequities as the majority of distributors' costs are fixed and hence could be more efficiently recovered via some form of fixed charge. We are encouraged by recent Government announcements that the Low User Regulation will be amended.

For further information on our future pricing developments, please see our electricity roadmap which is available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing under the heading "consumer-led pricing design". The roadmap is an evolving document and will updated periodically, but at least twice a year.

5 – HOW MASS MARKET AND UNMETERED PRICES ARE DERIVED

Like the previous year, for PY22 [11] our mass market price categories continue to be split into two pricing structures;

- two-part time of use - daily fixed price with different volumetric prices depending on the time period when the electricity is used (that has peak time pricing during 7am-11am and 5pm-9pm weekdays and off-peak pricing during other times), and
- flat volumetric pricing - daily fixed price and any anytime volumetric price, available only as an exemption to TOU of consumption information.

Our residential price categories include both controlled and uncontrolled price categories, with the controlled price categories designed to reward residential consumers for the benefit these households deliver to us in helping to reduce load during peak periods, via electrical hot water load control system or gas connections which typically use less electricity during peak periods.

Our residential prices are subject to the Low User Regulations, and we comply with these regulations by offering low user price categories for residential consumers at their primary place of residence with a fixed price of $0.15 per day and volume prices that ensure that consumers who use 8,000 kWh per year or less are better off on the low fixed price categories.

We have a two-part charge for unmetered price categories with fixed and volumetric prices. The fixed price is the number of days each point of connection of fitting is energised. Unmetered consumers' volumes are determined by us based on load profiles and fitting input wattages.

Table 4 shows the price components applicable to the price categories for the mass market and unmetered consumer groups. The price components for mass market and unmetered are the same as the previous year.

Table 4: Price components applicable to mass market and unmetered price categories from 1 April 2021

Consumer group and subgroup		Price category description	Price category code		Daily		Volume				
							anytime		off-peak	peak	injection
			Auckland	Northern	-FIXD		-24UC	-AICO	-OFPK	-PEAK	-INJT
					$/day	$/day/fitting	$/kWh				
Mass market	Residential	TOU - uncontrolled	ARHL, ARHS	WRHL, WRHS	✓				✓	✓	✓
Mass market	Residential	TOU - controlled	ARHLC, ARHSC	WRHLC, WRHSC	✓				✓	✓	✓
Mass market	Residential	Exemption - uncontrolled	ARUL, ARUS	WRUL, WRUS	✓		✓				✓
Mass market	Residential	Exemption - controlled	ARCL, ARCS	WRCL, WRCS	✓			✓			✓
Mass market	General	TOU	ABSH	WBSH	✓				✓	✓	✓
Mass market	General	Exemption	ABSN	WBSN	✓		✓				✓
Unmetered	General	Unmetered	ABSU	WBSU		✓	✓				✓

[11] Pricing year (PY) is the 12 month period from 1 April to 31 March each year. PY22 is 1 April 2021 to 31 March 2022

6 – HOW COMMERCIAL PRICES ARE DERIVED

Our price structure for commercial price categories is largely historical. There were (and, to a lesser extent, still are) a variety of price categories with different combinations of price components and price levels, due largely to pricing differences that existed prior to both networks being owned by us .

Current TOU price categories consist of a daily fixed (Northern network only), volume, capacity, demand, excess demand (for high voltage consumers) and power factor prices. Non-TOU price categories include daily fixed, volume, capacity and power factor prices (no demand prices).

We maintain a relativity in price levels between low voltage, transformer and high voltage price categories. Except for power factor prices, high voltage price levels are 97% of transformer price levels which are, in turn, 98% of low voltage price levels. This approach reflects the relative costs of serving these consumer groups.

Table 5 shows the price components applicable to the price categories for the commercial consumer groups, there is no change from the previous year.

Table 5: Price components applicable to commercial price categories

Consumer group	Price category description	Price category codes	Daily	Volume - anytime	Capacity	Demand	Excess demand	Power factor	Volume - injection
			-FIXD	-24UC	-CAPY	-DAMD	-DEXA	-PWRF	-INJT
			$/day	$/kWh	$/kVA/day			$/kVAr /day	$/kWh
Low voltage	TOU	ALVT		✓	✓	✓		✓	✓
		WLVH	✓	✓	✓	✓		✓	✓
	Non TOU	ALVN, WLVN	✓	✓	✓			✓	✓
Transformer	TOU	ATXT		✓	✓	✓		✓	✓
		WTXH	✓	✓	✓	✓		✓	✓
	Non TOU	ATXN, WTXN	✓	✓	✓			✓	✓
High voltage	TOU	AHVT		✓	✓	✓	✓	✓	✓
		WHVH	✓	✓	✓	✓	✓	✓	✓
	Non TOU	AHVN, WHVN	✓	✓	✓			✓	✓

7 – NON-STANDARD CONTRACTS & DISTRIBUTED GENERATION POLICIES

Table 6: Criteria for non-standard contracts

Approach	Description
Criteria	For any new investments required by consumers, we apply our capital contributions policy. Our policy for determining capital contributions on our electricity distribution network is available at http://vector.co.nz/disclosures/electricity/capital-contributions. When a new investment is recovered through capital contributions, standard pricing applies. Historical investments required by consumers and not recovered through capital contributions may be subject to non-standard contracts allowing for non-standard prices and tailored commercial arrangements to be applied to individual consumers.
Methodology	For determining prices for consumers subject to non-standard contracts, we use actual costs and/or allocated costs derived from an allocation model to determine prices. This allocation model is similar to the Cost of Service Model (COSM) used in assessing standard pricing.

Approach to pricing distributed generation

Our policies and procedures for installation and connection of distributed generation are in accordance with the requirements of Part 6 (Connection of distributed generation) of the Electricity Industry Participation Code 2010 (the Code).

We charge each distributed generator[12] prior to them connecting to the network based on the fees set out in Part 6 of the Code. We do not charge for connections smaller than 10 kW.[13]

We do not make Avoided Cost of Distribution payments to any distributed generators. We make Avoided Cost of Transmission (ACOT) payments to distributed generators in accordance with our ACOT methodology.

To date given the small number of distributed generation consumers, we have not identified any short run incremental costs from injection of energy into the network so this price continues to be $0.0000/kWh from 1 April 2021 for all distributed generators. As more distributed generation connects this may require more in-depth consideration and as a result pricing may change.

Further information on our policies for distributed generation can be found at https://www.vector.co.nz/personal/solar/connecting-your-generation-to-our-network.

[12] Distributed generator is a party with whom we have an agreement for the connection of plant or equipment to our electricity distribution network where the plant or equipment is capable of injecting electricity into our distribution network

[13] kW is kilowatt, a measure of electrical power. Also used for the measurement of demand during peak periods for the allocation of transmission charges from Transpower

8 – OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS

For PY22, our obligations and responsibilities to consumers in the event that the supply of electricity lines services to them is interrupted have no implications for determining prices.

A summary of our obligations and responsibilities to consumers subject to non-standard contracts on our network (in the event that the supply of electricity lines services to the consumer is interrupted) is provided in Table 7. Our standard contract terms and non-contract terms are also compared.

Table 7: Summary of our obligations and responsibilities to consumers

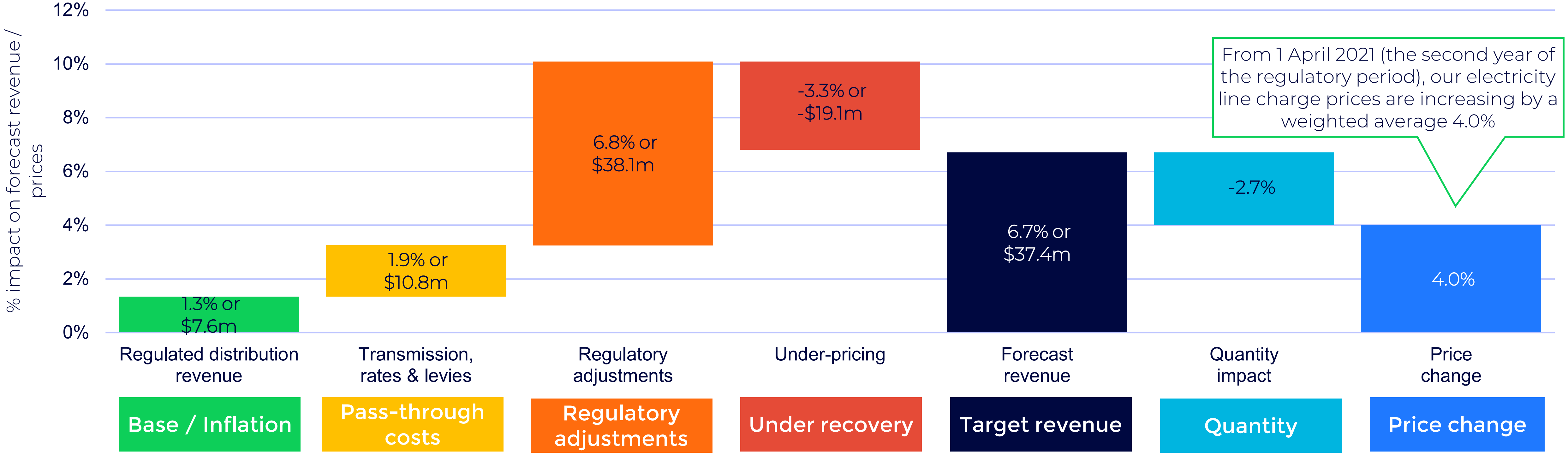
	Planned interruption notice	Unplanned interruption notice	Fault restoration	No. of interruptions per annum	No. of consumers
Standard	4 days	As soon as practicable but no later than: - 20 mins during staffed control room hours, - 40 mins during on-call control room hours	CBD/Industrial: 2 hours	Urban: 4	Approx. 592,000
			Urban: 2.5 hours		
			Rural: 4.5 hours	Rural: 10	
Non-standard	Same as standard consumers				1
	1 April each year, or 10 working days	As soon as practicable	2 hours	1 unplanned	1
	1 June each year	As soon as practicable	As soon as practicable	Not stated	2
	1 November each year	As soon as practicable	Priority	Not stated	6
	10 working days	As soon as practicable	3 hours	Not stated	7
	10 working days	Not stated	3 hours	Not stated	2
	10 working days	Not stated	Not stated	Not stated	2
	30 working days	As soon as practicable	As soon as practicable	Not stated	1
	4 working days	As soon as practicable	3 hours	Not stated	5
	7 working days	As soon as practicable	Priority	3 planned	2
	August each year	Not stated	1 hour	Not stated	1

9 – PRICE SETTING

Our prices are subject to the Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP Determination)[14] which states that to be compliant with the price path, forecast revenue (target revenue) must not exceed forecast allowable revenue (revenue cap).

Forecast allowable revenue equals the regulated distribution revenue (as set for every pricing year in the five year regulatory period adjusted for inflation) plus forecast pass-through costs (e.g. transmission costs, council rates and statutory levies) plus regulatory adjustments[15] (including any adjustment to cap the forecast allowable revenue increase to ten percent as required by the DPP Determination).

Figure 2: Change in PY22 forecast revenue and contribution to price change[16]



14 Available at https://comcom.govt.nz/regulated-industries/electricity-lines/ electricity-lines-price-quality-paths/electricity-lines-default-price-quality-path/ 2020-2025-default-price-quality-path

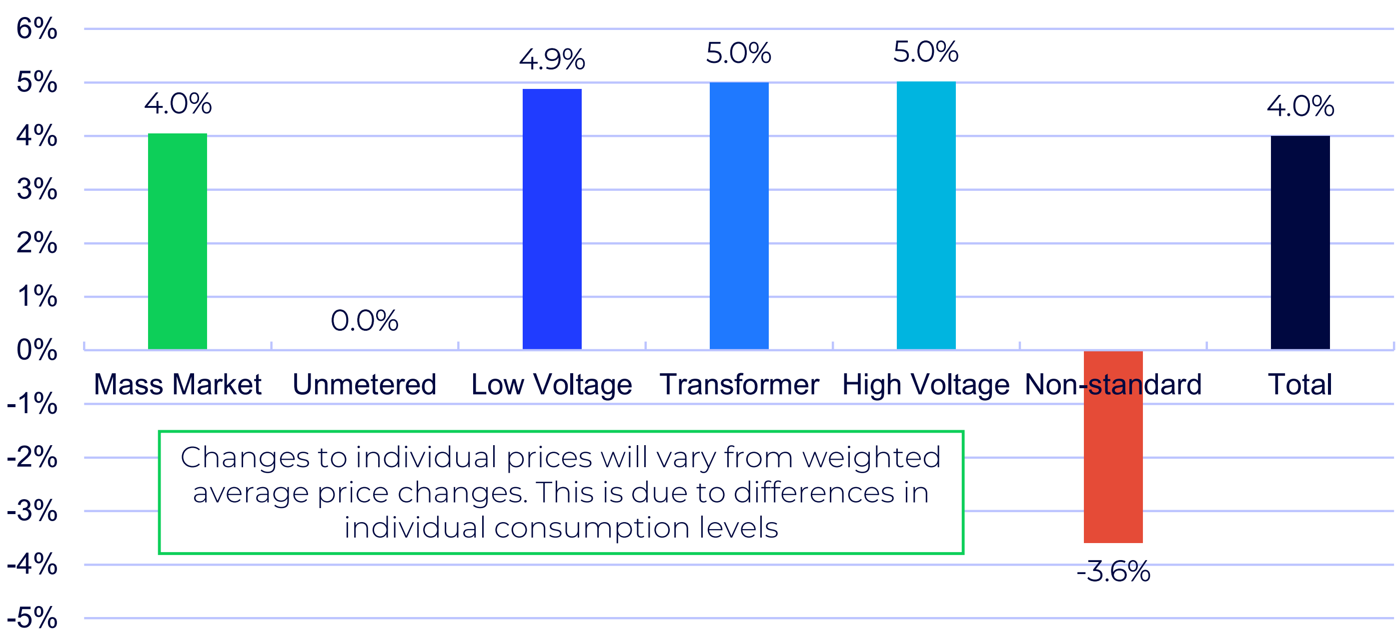
15 Regulatory adjustments are intangible recoverable costs (not invoiced) such as incentives and wash-ups that impact the amount of line charge revenue that we are allowed to recover. These wash-ups include incremental rolling incentive scheme (IRIS), quality incentive adjustment, capex wash-up adjustment and pass-through balance allowance and have time value of money included. The amount has been adjusted down to meet the revenue cap

16 Vector's forecast revenue is set to under recover by $19.1m

10 – PRICE CHANGES

We are conscious of the effect of price changes for consumers. Our starting point for calculating prices is the corresponding price from the previous year. Historic consumer groups and price categories have been. Figure 3 shows how the weighted average price change is split across the consumer groups. Our electricity prices that apply from 1 April 2021, including the previous year's prices that were effective from 1 April 2020, are set out in Appendix 1.[17]

Figure 3: Weighted average price change by consumer group



Unmetered consumers' prices are unchanged as are transitioning back to the COSM range. Non-standard price changes as per contracts and with forecast contract renewals having a lower price predominantly due to the lower WACC in the current regulatory period.

For mass market consumers, time of use plans are mandatory, with exemptions granted only where retailers don't obtain the ICPs interval data. The price increase is primarily passed through fixed (for standard residential and general) and TOU peak prices. General continues to match residential standard user uncontrolled.

The decision to primarily increase the fixed prices for mass market consumers reflects the fact that the majority of our costs are fixed and sunk, so increasing the fixed portion of revenues aligns the recovery of revenues with the way costs are incurred.

For commercial consumers, the price increase is applied uniformly across all price components except power factor which stays the same (consistent with previous years approaches). With the variety of commercial consumers' consumption profiles, this approach was taken to closely align the weighted average change across the price categories.

We did not directly seek the views of consumers when setting prices. Rather, we consulted with Entrust, whose beneficiaries are mass market consumers on the Auckland network, and retailers on behalf of consumers on the proposed price changes. We have considered and largely accommodated their feedback in our final prices.

[17] Our full price schedules are available at https://www.vector.co.nz/personal/electricity/about-our-network/pricing

11 – TARGET REVENUE AND ITS CATEGORISATION

Our COSM is used to allocate target revenue to consumer groups using various cost drivers. The model structure is outlined in Figure 4.

Target revenue is the total revenue we expect to recover from our prices (complying with the regulated price path) and our forecasted quantities. The total target revenue for PY22 is $603.0m ($565.2m for PY21).

The total target revenue is broken down into the key components required to cover the costs and return on investment associated with the provision of electricity distribution services as shown in Figure 5. These key components are categorised by cost driver i.e. either 'asset', 'non-asset', 'transmission' or 'profit'. These categorisations are summarised in Figure 6 determine the way that the target revenue is allocated to consumer groups.

Figure 4: COSM structure

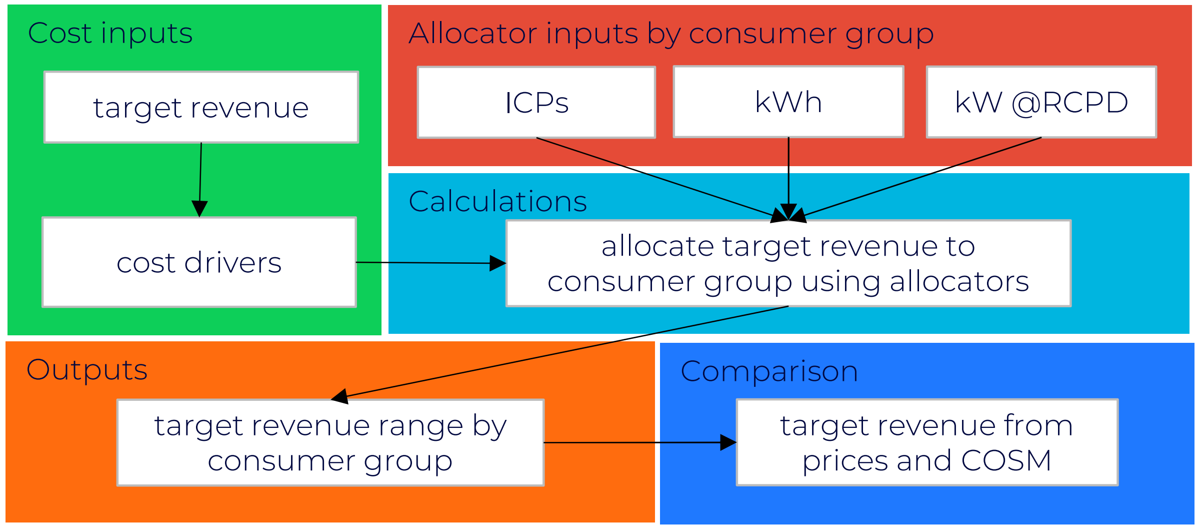


Figure 5: Target revenue by key components

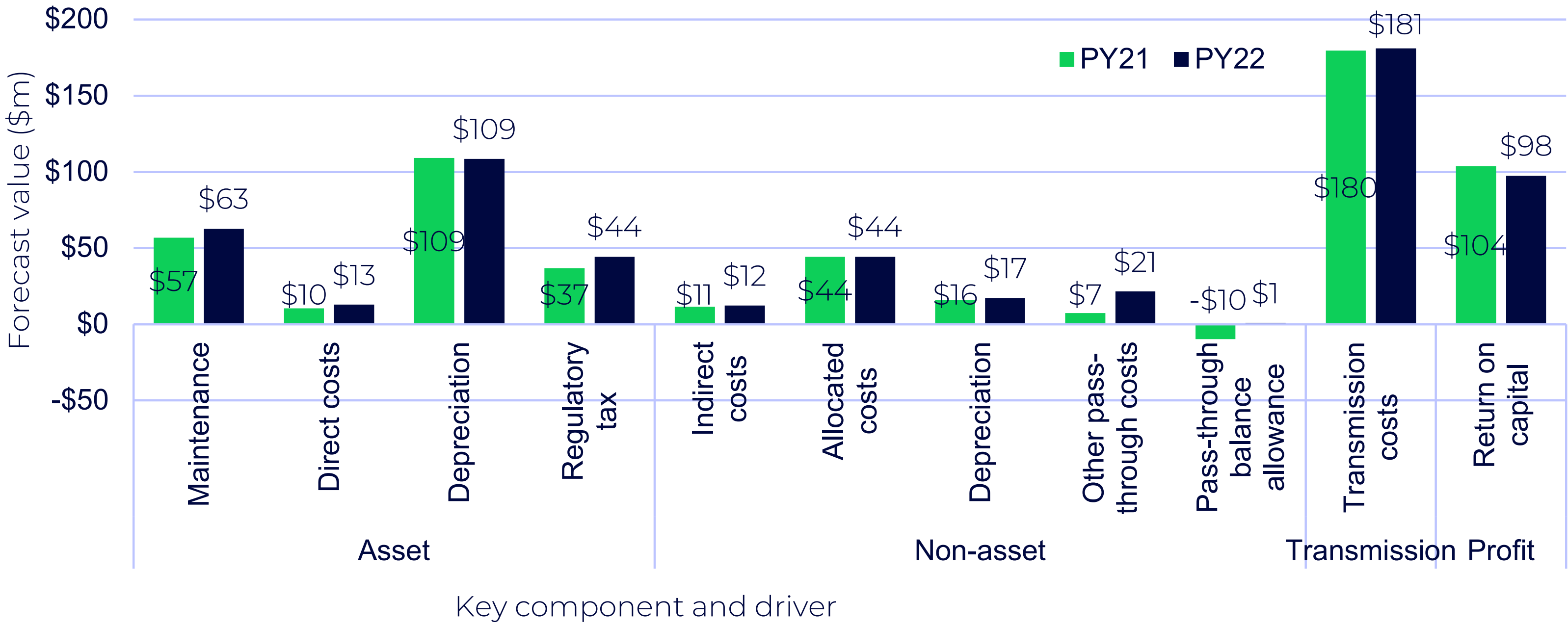


Figure 6: Target revenue by cost driver

12 – COST DRIVERS

The key components categorised as 'asset costs' are those associated with expenditure and return on the electricity distribution network assets. We have grouped these network assets into three distinct categories as shown in Table 8.

We assume that costs associated with assets are incurred in proportion to the value of the assets. For example, as Category A assets make up 72% of the asset value of our Regulatory Asset Base (RAB)[18], we assume that 72% of maintenance costs will be associated with Category A assets.

A key feature of an electricity distribution network is interconnected assets. Many consumers on the network share assets and it is difficult to identify precisely who benefits from which assets. While this means that the allocation of target revenue between consumers or groups of consumers can be made in many ways, it also means that the cost of providing the network is shared widely and therefore the cost of network services is generally low for each consumer.

The cost drivers of 'Asset', 'Non-Asset', 'Transmission' and 'Profit' are applied to the combined Northern and Auckland networks. Our COSM allocates the recovery of the $603.0m to consumer groups using various cost drivers as summarised in Table 9.

[18] Broadly the regulatory asset base represents the amount that we have invested in our regulated network, indexed to inflation and adjusted for depreciation

[19] The values are weighted averages of the last five years' worth of data, with each year being weighted twice the previous year. Contribution to RCPD not obtained for previous year as aggregated interval consumption data by consumer group was unable to be provided to Vector

Table 8: Asset categorisation

Asset category	Assets	Consumer groups	Asset value [19] (RAB)	
A	• Sub-transmission lines / cables • Zone-substations • HV lines / cables	All	$2,319m	72%
B	• Distribution substations that have no Vector-owned low voltage lines / cables leaving the substation	Transformer	$61m	2%
C	• Distribution substations that: o have Vector-owned low voltage lines leaving the substation, or o supply multiple end-consumers connected at low voltage • Low voltage assets	Low voltage, unmetered, mass market	$842m	26%

Table 9: Cost drivers used in the COSM

<table>
<tr><th rowspan="2">Consumer group</th><th colspan="3">Asset</th><th rowspan="2">Non-asset</th><th rowspan="2">Transmission</th><th rowspan="2">Profit</th></tr>
<tr><th>A</th><th>B</th><th>C</th></tr>
<tr><td>Amount</td><td>$164.4m</td><td>$4.3m</td><td>$59.7m</td><td>$96.1m</td><td>$181.0m</td><td>$97.5m</td></tr>
<tr><td>Mass market</td><td rowspan="5">Contribution to RCPD</td><td rowspan="3">n/a</td><td rowspan="3">Contribution to RCPD or annual consumption</td><td rowspan="5">Number of consumers or annual consumption</td><td rowspan="5">Contribution to RCPD</td><td rowspan="5">Rate of return on assets</td></tr>
<tr><td>Unmetered</td></tr>
<tr><td>Low voltage</td></tr>
<tr><td>Transformer</td><td>Direct</td><td rowspan="2">n/a</td></tr>
<tr><td>High voltage</td><td>n/a</td></tr>
</table>

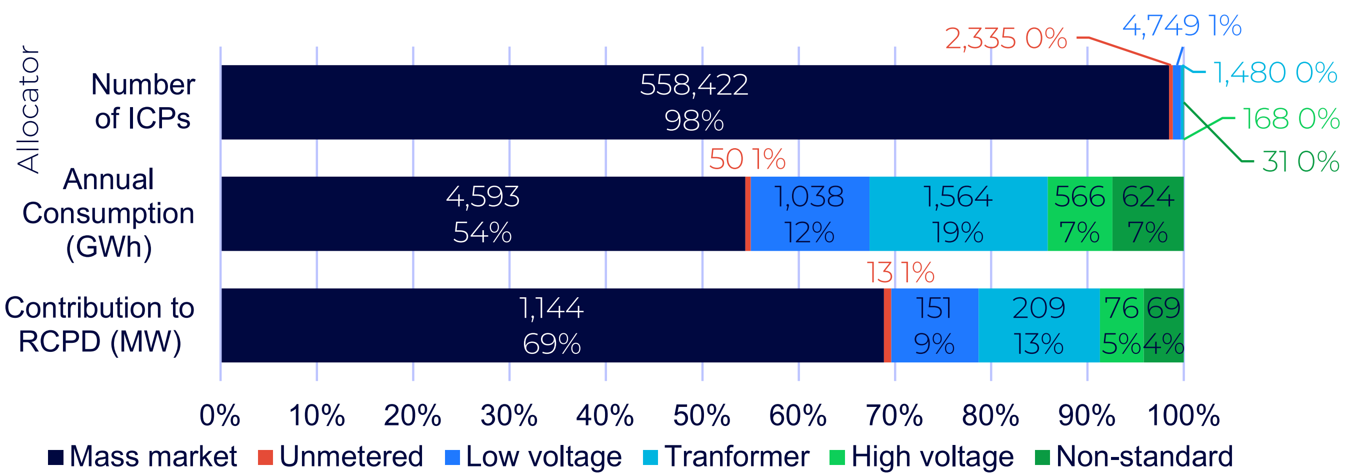
13 – COST DRIVER ALLOCATION APPROACHES

We aim to allocate asset-related costs on the basis of a consumer group's usage of the assets during peak periods, as this usage drives the need for, and the size of, the assets.

- For Category A assets, an appropriate and readily available measure to allocate their costs, is consumer group's contribution to Transpower's Regional Coincident Peak Demand (RCPD)[20] periods.
- For Category B assets, the costs do not require an allocation approach as they are used by one consumer group (transformer consumers).
- For Category C assets, that are assets located close to the end consumer, appropriate readily-available allocators are contribution to RCPD and annual consumption. We use both allocators to generate a band of cost allocation values as no one allocator is preferred to the other.

Non-asset costs' can be broadly summarised as overhead costs and pass-through costs (other than transmission costs). Costs categorised as 'Non-asset' have no direct cost driver. We have chosen to create a band of cost allocations using annual consumption and the number of consumers as the allocators.

Figure 7: PY22 COSM allocation values and percentage[21]



Costs categorised as 'Transmission' are transmission charges from Transpower that we pass through to consumers. Transmission interconnection costs (which form the majority of transmission charges) are charged to us by Transpower on the basis of demand during RCPD periods. We mirror this approach by allocating transmission costs to each consumer group on the basis of that consumer group's demand during these RCPD periods.

'Profit' is the return on capital and is broadly generated through the usage of Vector's assets. A consumer groups' asset values are calculated in the same way as 'Asset' related costs are. 'Profit' is allocated using a constant rate of return across the consumer groups' asset values.

[20] RCPD for a Transmission Region is the sum of the offtake measured in kW in that Region during Regional Coincident Peak Demand Periods, as determined by Transpower each year. Where a Transmission Region is one of the four regional groups of connection locations (as defined in Transpower's Transmission Pricing Methodology), Upper North Island, Lower North Island, Upper South Island, and Lower South Island; and Regional Coincident Peak Demand Period means for the Upper North Island a half hour in which any of the 100 highest regional demands (measured in kW) occurs during 1 September to 30 August immediately prior to the start of the Pricing Year

[21] Weighted average of last five year's values from the billed quantities in Schedule 8 of our annual Electricity Information Disclosures (available at [https://www.vector.co.nz/about-us/regulatory/ disclosures-electricity/financial-and-network-information](https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/financial-and-network-information)), with each year being weighted twice the previous year

14 – TARGET REVENUE ALLOCATION & PRICE COMPARISON

The result of using the different allocators for category C ‘asset costs’ and ‘non-asset costs’ creates a target revenue range by consumer group as the use of different allocators gives rise to different target revenue allocation results. The bands represent the lower and upper bounds of the different allocation approaches, as shown in Figure 8 which shows target revenue calculated from PY22 prices by consumer group compared with the COSM allocations. The result is that PY22 prices produce forecasts that are in or near an acceptable range when compared to target revenue allocations.

The pricing for non-standard consumers is calculated as per their contracts and is separate from the other consumer groups. The COSM is calibrated to produce the forecasted target revenue of $17.8m (2.9%) to be recovered from the 24 non-standard consumers (30 ICPs).

Price setting is an iterative process, where the prices are only finalised once the price path compliance is managed, bill impacts are fair and tolerable and prices deliver revenue from each consumer group consistent with their target revenue allocation

The proportion of the aggregated price categories’ target revenue is shown by price component in Figure 9. All price categories within the aggregation have similar proportioned price components. Please see Appendix 2 for the proportion of target revenue split by individual price category and price component.

Figure 8: PY22 target revenue from prices compared with COSM allocations

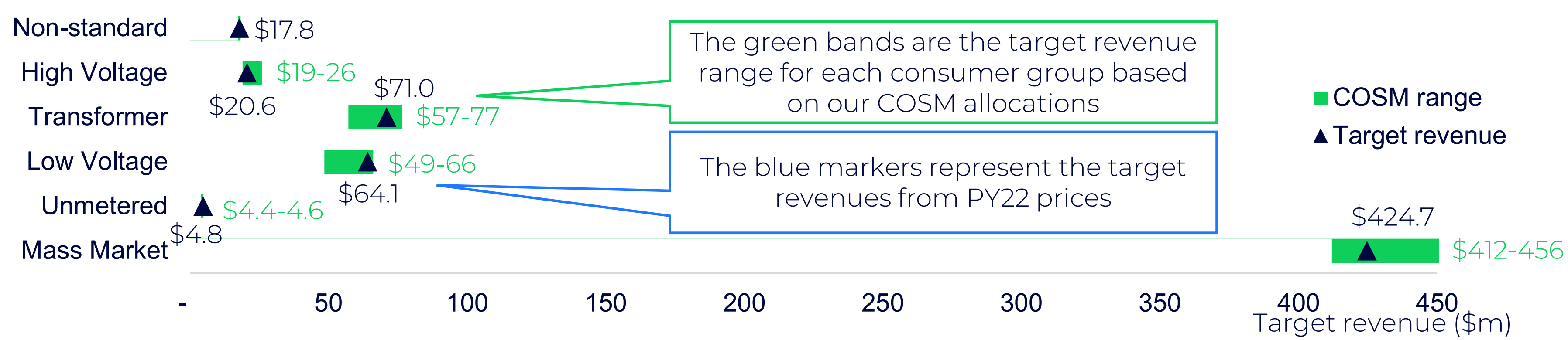
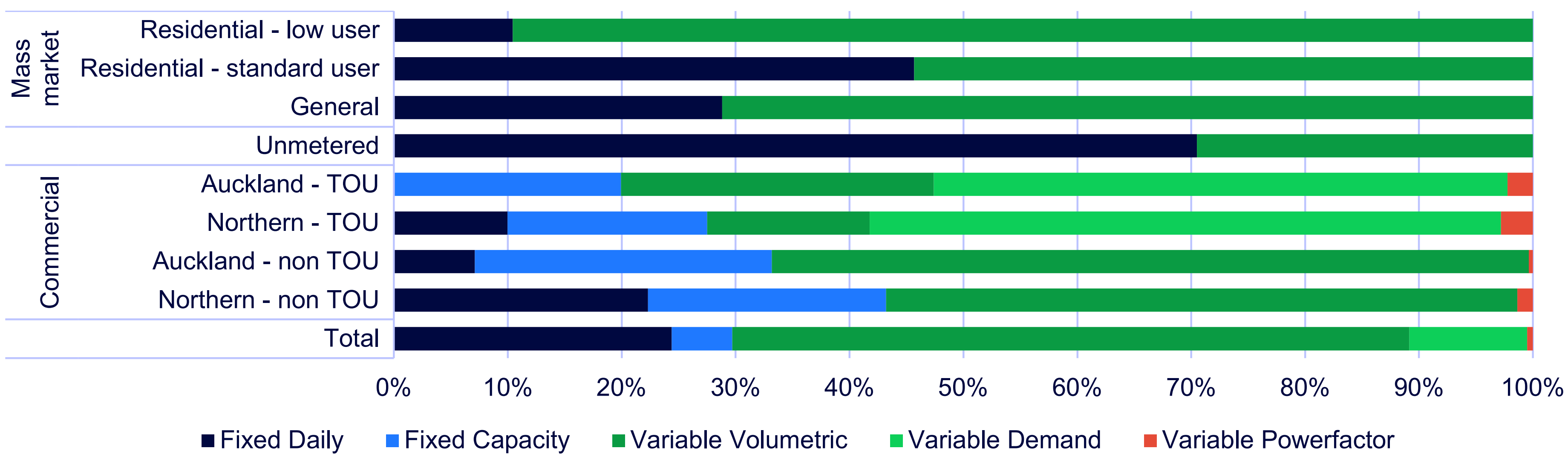


Figure 9: Proportion of PY22 target revenue by price component and category



APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2021

Table 10: Mass market and unmetered line charges prices
(previous price, if changing)

Consumer group and subgroup		Price category type	Price category description	Price category codes	Estimated number of consumers (PY22 avg.)	Total line charge prices – Daily – $/day -FIXD	Total line charge prices – Daily – $/day/fitting -FIXD	Total line charge prices – Volume – anytime – $/kWh -24UC	Total line charge prices – Volume – anytime – $/kWh -AICO	Total line charge prices – Volume – off-peak – $/kWh -OFPK	Total line charge prices – Volume – peak – $/kWh -PEAK	Total line charge prices – Volume – injection – $/kWh -INJT	Transmission charge price* – Volume – anytime or peak – $/kWh -24UC, -AICO or -PEAK
Mass market	Residential - low user	TOU	Uncontrolled	ARHL WRHL	29,544 20,269	0.15				0.0658 *(0.0621)*	0.1647* *(0.1542)**	-	0.0992 *(0.0921)*
Mass market	Residential - low user	TOU	Controlled	ARHLC WRHLC	162,839 105,614	0.15				0.0658 *(0.0621)*	0.1446* *(0.1354)*	-	0.0791 *(0.0733)*
Mass market	Residential - low user	Exemption	Uncontrolled	ARUL WRUL	820 562	0.15		0.0963* *(0.0925)**				-	0.0349 *(0.0369)*
Mass market	Residential - low user	Exemption	Controlled	ARCL WRCL	4,644 3,026	0.15			0.0901* *(0.0863)**			-	0.0287 *(0.0307)*
Mass market	Residential - standard	TOU	Uncontrolled	ARHS WRHS	16,670 15,596	1.09 *(1.01)*				0.0230 *(0.0229)*	0.1219* *(0.1150)**	-	0.0992 *(0.0921)*
Mass market	Residential - standard	TOU	Controlled	ARHSC WRHSC	90,254 68,402	1.09 *(1.01)*				0.0230 *(0.0229)*	0.1018 *(0.0962)*	-	0.0791 *(0.0733)*
Mass market	Residential - standard	Exemption	Uncontrolled	ARUS WRUS	463 433	1.09 *(1.01)*		0.0535* *(0.0533)**				-	0.0349 *(0.0369)*
Mass market	Residential - standard	Exemption	Controlled	ARCS WRCS	2,379 1,803	1.09 *(1.01)*			0.0473* *(0.0471)**			-	0.0287 *(0.0307)*
Mass market	General	TOU		ABSH WBSH	31,708 19,552	1.09 *(1.01)*				0.0230 *(0.0229)*	0.1219* *(0.1150)**	-	0.0992 *(0.0921)*
Mass market	General	Exemption		ABSN WBSN	5,076 3,130	1.09 *(1.01)*		0.0535* *(0.0533)**				-	0.0349 *(0.0369)*
Unmetered	General	Unmetered		ABSU WBSU	1,707 706		0.08	0.0257*				-	0.0196 *(0.0260)*

* The transmission charge price is only included in this component of the line charge price

APPENDIX 1 - LINE CHARGE PRICES FROM 1 APRIL 2021

Table 11: Commercial line charge prices
(previous price, if changing)

Consumer group	Price category description	Price category code	Estimated number of consumers (PY22 avg.)	Total line charge prices							Transmission charge price*
				Daily	Capacity	Volume anytime	Demand	Excess demand	Power factor	Volume injection	Volume anytime or Demand
				$/day -FIXD	$/kVA/day -CAPY	$/kWh -24UC	$/kVA/day -DAMD	$/kVA/day -DEXA	$/kVAr/day -PWRF	$/kWh -INJT	$/kWh or $/kVA/day -24UC or -DAMD
Low voltage	Non TOU	ALVN	2,322	1.87 *(1.78)*	0.0441 *(0.0421)*	0.0568* *(0.0541)**			0.2917	-	0.0181 *(0.0187)*
		WLVN	916	6.04 *(5.74)*	0.0356 *(0.0339)*	0.0351* *(0.0335)**			0.2917	-	0.0181 *(0.0187)*
	TOU	ALVT	1,440		0.0441 *(0.0421)*	0.0126 *(0.0120)*	0.3063* *(0.2917)**		0.2917	-	0.1828 *(0.1900)*
		WLVH	262	11.37 *(10.82)*	0.0356 *(0.0339)*	0.0054 *(0.0050)*	0.2759* *(0.2628)**		0.2917	-	0.1828 *(0.1900)*
Transformer	Non TOU	ATXN	161	1.83 *(1.74)*	0.0432 *(0.0412)*	0.0557* *(0.0530)**			0.2917	-	0.0181 *(0.0187)*
		WTXN	134	5.92 *(5.63)*	0.0349 *(0.0332)*	0.0344* *(0.0328)**			0.2917	-	0.0181 *(0.0187)*
	TOU	ATXT	948		0.0432 *(0.0412)*	0.0123 *(0.0117)*	0.3001* *(0.2858)**		0.2917	-	0.1828 *(0.1900)*
		WTXH	282	11.15 *(10.61)*	0.0349 *(0.0332)*	0.0053 *(0.0049)*	0.2704* *(0.2575)**		0.2917	-	0.1828 *(0.1900)*
High voltage	Non TOU	AHVN	7	1.77 *(1.68)*	0.0419 *(0.0399)*	0.0540* *(0.0514)**			0.2917	-	0.0181 *(0.0187)*
		WHVN	0	5.74 *(5.46)*	0.0339 *(0.0322)*	0.0334* *(0.0318)**			0.2917	-	0.0181 *(0.0187)*
	TOU	AHVT	142		0.0419 *(0.0399)*	0.0119 *(0.0113)*	0.2910* *(0.2772)**	0.9218 *(0.8778)*	0.2917	-	0.1828 *(0.1900)*
		WHVH	24	10.82 *(10.30)*	0.0339 *(0.0322)*	0.0051 *(0.0048)*	0.2623* *(0.2498)**	0.7458 *(0.7084)*	0.2917	-	0.1828 *(0.1900)*

* The transmission charge price is only included in this component of the line charge price

APPENDIX 2 –TARGET REVENUE RECOVERY

Table 12: Proportion of mass market target revenue by price component

Consumer group and subgroup		Price category description	Code	Fixed	Variable	Code	Fixed	Variable
			Auckland	Daily	Volumetric	Northern	Daily	Volumetric
Mass market	Residential - low user	TOU - uncontrolled	ARHL	0.27%	2.36%	WRHL	0.18%	1.73%
		TOU - controlled	ARHLC	1.48%	12.21%	WRHLC	0.96%	8.39%
		Exemption - uncontrolled	ARUL	0.01%	0.06%	WRUL	0.01%	0.05%
		Exemption - controlled	ARCL	0.04%	0.47%	WRCL	0.03%	0.27%
	Residential - standard user	TOU - uncontrolled	ARHS	1.10%	1.41%	WRHS	1.03%	1.38%
		TOU - controlled	ARHSC	5.95%	6.79%	WRHSC	4.51%	5.37%
		Exemption - uncontrolled	ARUS	0.03%	0.03%	WRUS	0.03%	0.03%
		Exemption - controlled	ARCS	0.16%	0.23%	WRCS	0.12%	0.15%
	General	TOU	ABSH	2.09%	5.39%	WBSH	1.29%	2.91%
		Exemption	ABSN	0.33%	0.91%	WBSN	0.21%	0.48%
Unmetered		Unmetered	ABSU	0.35%	0.15%	WBSU	0.22%	0.09%

Table 13: Proportion of commercial target revenue by price component

Consumer group	Short description	Category	Fixed		Variable			Category	Fixed		Variable		
		Auckland	Daily	Capacity	Volumetric	Demand	Power factor	Northern	Daily	Capacity	Volumetric	Demand	Power factor
Low voltage	TOU	ALVT	-	1.02%	1.19%	2.31%	0.15%	WLVH	0.18%	0.15%	0.12%	0.48%	0.03%
	Non TOU	ALVN	0.26%	0.93%	2.41%	-	0.01%	WLVN	0.33%	0.29%	0.74%	-	0.02%
Transformer	TOU	ATXT	-	1.80%	2.41%	4.40%	0.16%	WTXH	0.19%	0.45%	0.33%	1.30%	0.06%
	Non TOU	ATXN	0.02%	0.10%	0.22%	-	0.00%	WTXN	0.05%	0.07%	0.21%	-	0.01%
High voltage	TOU	AHVT	-	0.42%	0.86%	1.48%	0.05%	WHVH	0.02%	0.08%	0.10%	0.37%	0.01%
	Non TOU	AHVN	0.00%	0.00%	0.01%	-	0.00%	WHVN	-	-	-	-	-

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

The Electricity Authority's Pricing Principles[22] (Pricing Principles) provide guidance to developing pricing methodologies for electricity distribution services. Table 14 demonstrates the extent to which the Pricing Methodology is consistent with the Pricing Principles.

Table 14: Pricing principles

Principle (a): Economic costs of service provision *Prices are to signal the economic costs of service provision, including by:* *i. being subsidy free (equal to or greater than avoidable costs and less than or equal to standalone costs);* *ii. reflecting the impacts of network use on economic costs;* *iii. reflecting differences in network service provided to (or by) consumers; and,* *iv. encouraging efficient network alternatives.*
The avoidable cost test can be applied both for individual consumers and for groups of consumers. The avoidable cost for an individual consumer is the cost of connecting that consumer to the network, and therefore excludes the cost of shared assets. The avoidable cost for a group of consumers is the cost of connecting that group of consumers to the network, and includes the cost of assets shared by that group. Our capital contributions policy ensures that individual consumers generally pay the costs of connecting to the network. Applying the avoidable cost test at a group level is more stringent because it includes shared costs for the group. Revenues for the group must be higher than just the sum of the avoidable cost for each individual consumer. While we monitor the cost of a range of alternative options for consumers, it can be difficult to apply these on a consumer-specific basis. In some instances, the economic value of the service, including where that is set by the cost of an alternative form of supply, may be notified to us by the consumer. In these situations, this pricing principle is delivered through the operation of pricing principle (c), detailed below. The electricity distribution system consists of assets with significant capacity. When building the system, economies of scale exist such that the cost of installing an asset larger than that which is immediately required does not add significantly to the cost of network build. As a consequence, some parts of the distribution system have spare capacity. In most cases, due to the availability of spare capacity, the short run cost of the next unit of capacity is significantly less than the average cost.

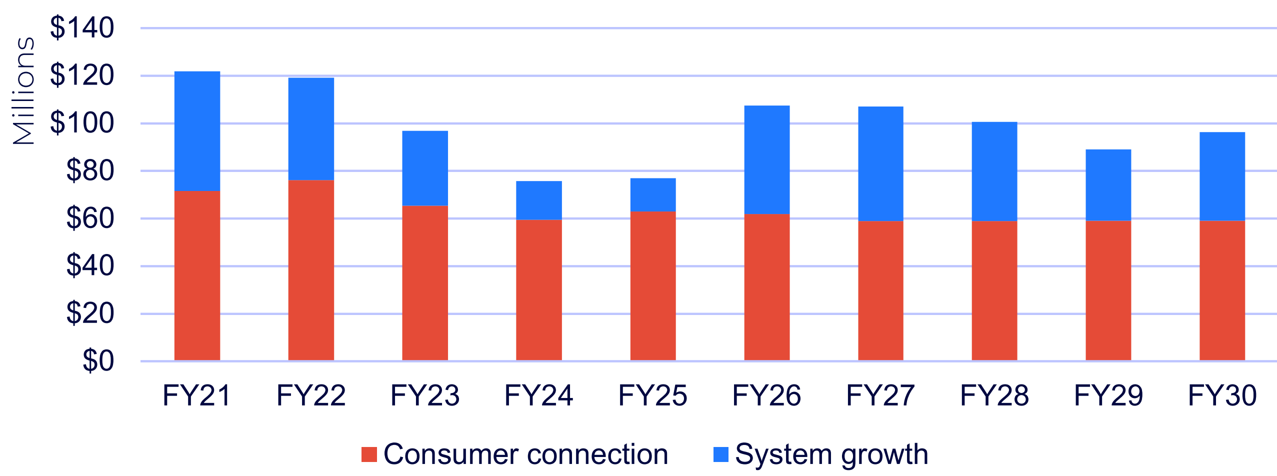
[22] Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/development/summary-of-submissions-and-decision-paper

Principle (a): Economic costs of service provision (cont.)

Some areas of our network have high utilisation and the system requires expansion (for example, to connect a new user to the distribution system). We generally fund this expansion through capital contributions and/or non-standard prices which ensure recovery of the incremental capital investment. Our approach to recovering these costs is outlined in our electricity distribution capital contribution policy.

Figure 10 shows our forecast capital expenditure excluding capital contributions to meet future demand from our 2020 Asset Management Plan[27]. Consumer connections allow for the costs of connecting new consumers and reticulating new subdivisions, while system growth relates to expansion of the network to provide the capacity to meet the electricity needs of all connections.

Figure 10: Forecast capital expenditure to meet future demand



Our target revenue allocation illustrates how we utilise relevant cost drivers. We translate these into prices taking account of the materiality of the costs, our ability to estimate and signal the costs as well as the ability of participants to respond. We also consider important consumer aspects such as predictability, bill stability and equity.

Broadly we signal the level of available capacity and future investment costs over different time periods using time of use prices and controlled load prices. Prices for commercial consumers are structured in a very service reflective manner, utilising a variety of prices (daily, capacity, demand, volumetric, power factor) while our mass market prices are two part time of use, reflecting that peak usage is a general driver of investment over time. We offer controlled load prices to residential end consumers in return for the ability to remotely manage their hot water cylinders. This pricing approach signals the benefits to consumers of allowing us to control their hot water load and manage network congestion during peak periods through lower price options. These pricing options provide incentives to end consumers, (but only to the extent that retailers reflect those incentives to consumers) to shift demand away from peak periods and therefore reduce the need for future investment costs.

[27] Available at https://www.vector.co.nz/about-us/regulatory/disclosures-electricity/asset-management-plan

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

<u>Principle (b): Recovery of any shortfall</u> *Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.*
Pricing based on avoidable costs would almost certainly under-recover allowed revenues as the majority of our costs are fixed, so do not vary with the next unit of consumption. Our fixed costs are generally also sunk, so do not reduce if consumption reduces. Accordingly, the Pricing Methodology attempts to recover allowed target revenues in a manner that is as least distortionary as possible to investment decisions. As we have limited information of demand responsiveness by consumer group, we allocate the shortfall across all consumer groups.
<u>Principle (c): Responsive to requirements of consumers</u> *Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:* *i. reflect the economic value of services;* *ii. enable price/quality trade-offs.*
We offer non-standard pricing in certain circumstances including where standard pricing would cause uneconomic bypass of the network. Non-standard contractual arrangements are also able to address changes to the structure or level of prices (e.g. for atypical load patterns, or to address particular by-pass or fuel substitute situations), and differing service levels (e.g. a higher level of redundancy, or priority response if an outage occurs). The Pricing Methodology obliges us to take account of the issues described above when considering the design of a non-standard contract. The Pricing Methodology does not provide specific incentives for investment in transmission and distribution alternatives. Where the connection of new load requires investment in the network (e.g. new subdivisions) then the cost of that investment is recovered via capital contributions and/or non-standard prices. Those prices provide the economic incentive for transmission and distribution alternatives to be investigated by the proponent of the development. For example, a new subdivision that adapts new technologies to reduce load will not require the same level of network investment.

APPENDIX 3 – CONSISTENCY WITH PRICING PRINCIPLES

<u>Principle (d): Pricing process</u>

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

We believe that a simple pricing structure enhances transparency. Costs are clearly identified and allocated to consumer groups on a simple and transparent basis.

A simple pricing structure reduces the likelihood that changes in consumer behaviour will result in significant changes to cost allocations between consumer groups. A simple pricing structure also makes it easier for consumers to understand and estimate their likely costs.

We are particularly conscious of the effect of our pricing on consumers and seek to implement a pricing framework that provides appropriate incentives for consumers to continue to use our distribution services. Our decision to move mass market and general to two part time of use followed extensive modelling of consumer effects for a range of potential pricing structures that considered the consumer impacts and incentives. We have consulted with stakeholders, including retailers and Entrust, and obtained consumer insights through application of detailed data analytics in the development of this Pricing Methodology and we continue to consult as appropriate when applying it and future methodologies. The information we receive helps us to understand consumer drivers and preferences. We continue to undertake a range of trials so that we can anticipate and respond to consumer's requirements as technology changes the future of energy. As previously mentioned, we update and publish our pricing roadmap on a regular basis.

In recent years we have simplified our distribution price structure so that the transaction costs on retailers, end consumers, and ourselves are minimised. We offer retailers and Entrust the opportunity to comment on our proposed price structures each year. This provides an opportunity for these stakeholders to identify any proposals that may increase transaction costs, and provides us the opportunity to address any concerns they may have.

We offer the same network pricing to all end consumers irrespective of which retailer they use i.e. we do not provide any discounts or special terms to end consumers who are supplied by a particular retailer. The non-differentiation of network prices is outlined in the agreements that we have with retailers operating on our network.

We expect to continue to evolve our pricing as consumer's respond to the range of choices they have through technological innovation and increasing electrification, and regulatory reforms such as the Low User Regulations. Our intent is to provide a clear pathway to the new energy future.

APPENDIX 4 – DIRECTORS' CERTIFICATION

Schedule 17: Certification for Pricing Methodology Disclosure

Clause 2.9.1

We, Jonathan Mason and

Paula Rebstock, being directors of Vector Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Vector Limited prepared for the purposes of clauses 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Jonathan P. Mason

Director

Dame Paula Rebstock

Director

22 February 2021

Date