ELECTRICITY PRICING METHODOLOGY 2017

EFFECTIVE 1 APRIL 2017

DISCLOSED IN ACCORDANCE WITH SECTION 2.4.1 OF THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012

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1. DEFINITIONS

This pricing methodology uses industry standard terms where possible. A glossary of common terms is included for clarity. Additional information on definitions used in the document can be found in:

- Powerco's Electricity Pricing Schedule, Distributed Generation Policy and Asset Management Plan[1]; and
- The Commerce Commission's electricity default price-quality path notice and information disclosure requirements.[2]

"Anytime Maximum Demand" (AMD) means, in respect of a Western Region Consumer, on a 12-month rolling basis the highest kVA peak occurring at anytime for that Consumer. In respect of an Eastern Region Consumer, AMD means the highest kW peak occurring any time in the twelve month period from 1 January to 31 December, the result of which is applied in the subsequent Price Year commencing 1 April.

"Avoided Cost of Transmission" (ACOT) is the amount equal to the actual reduction in the interconnection charges of new investment charges that are payable by Powerco to Transpower under the Grid Network Agreement. ACOT charges are a substitute for what otherwise would have been Transpower charges.

"Coincident Maximum Demand" (CMD) see "On Peak Demand"

"Connection" or "Point of Connection" means each point of connection at which a supply of electricity may flow between the Distribution Network and the Consumer's installation, as defined by the Distributor.

"Consumer" means a purchaser of electricity from the Retailer where the electricity is delivered via the Distribution Network.

"Customer" means a direct Customer or a Retailer (where the Retailer is the Customer).

"Default Price Path – DPP" means Powerco's compliance with clause 8 of the Commerce Act (Electricity Distribution Default Price Quality Path) Determination 2010.[3]

"Demand" means the rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).

"Distributed Generation" or "Embedded Generation" means electricity generation that is connected and distributed within the Network.

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[1] Available at www.powerco.co.nz.
[2] Available at www.comcom.govt.nz.
[3] The DPP is described in more detail on the Commerce Commission's website, http://www.comcom.govt.nz/electricity-default-price-quality-path/

“Distributed Generator” or “Embedded Generator” means an electricity generation plant producing Embedded Generation.

“Distribution Network” or “Network” means:

DISTRIBUTION NETWORK	
EASTERN REGION	Valley – the Distribution Network connected to the Transpower transmission system at the GXPs at: Kinleith Kopu Hinuera Piako Waihou Waikino
	Tauranga – the Distribution Network connected to the Transpower transmission system at the GXPs at: Tauranga Mt Maunganui Te Matai Kaitimako
WESTERN REGION	Wairarapa – the Distribution Network connected to the Transpower transmission system at the GXPs at: Greytown Masterton
	Manawatu – the Distribution Network connected to the Transpower transmission system at the GXPs at: Bunnythorpe Linton Mangamaire
	Taranaki – the Distribution Network connected to the Transpower transmission system at the GXPs at: Carrington Huirangi Hawera New Plymouth Opunake Stratford
	Wanganui – the Distribution Network connected to the Transpower transmission system at the GXPs at: Brunswick Marton Mataroa Ohakune Wanganui Waverley

“Distributor” means Powerco Limited, as the operator and owner of the Distribution Networks, and includes its subsidiaries, successors and assignees.

“Electricity Authority” (EA) means the Electricity Authority which is an independent Crown entity responsible for regulating the New Zealand electricity market.

“Grid Exit Point” (GXP) means a point of connection between Transpower’s transmission system and the Distributor’s Network.

“High-Voltage” (HV) means voltage above 1,000 volts, generally 11,000 volts, for supply to Consumers.

“Installation Control Point” (ICP) means a Point of Connection on the Distributor’s Network, which the Distributor nominates as the point at which a Retailer is deemed to supply electricity to a Consumer, and has the attributes set out in the Code.

“kVA” means kilovolt–ampere (amp).

“kVAh” means kilovolt ampere hour.

“kVAr” means kilovolt ampere reactive.

“kW” means kilowatt.

“kWh” means kilowatt hour.

“Line Charges” means the charges levied by the Distributor on Customers for the use of the Distribution Network, as described in the Pricing Schedule.

“Low Voltage” (LV) means voltage of value up to 1,000 volts, generally 230 or 400 volts for supply to Consumers.

“MVA” means Megavolt Ampere.

“Network” see Distribution Network.

“Optimised Deprival Value” (ODV) means, in respect of the Distributor’s assets, the value attributed by applying the ODV methodology, as set out in the Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses published by the Commerce Commission in 2004.

“Optimised Replacement Cost” (ORC) is an estimate of the current cost of replacing the asset with one that can provide the required service in the most efficient way. Under this approach, asset values are adjusted if assets exhibit excess capacity, are over-engineered, are poorly designed (compared with modern technology) or are poorly located.

“Optimised Depreciated Replacement Cost” (ODRC) is an estimate of the ORC value, less an allowance for depreciation that reflects the age of the asset.

“On Peak Demand” (OPD) is the average of Consumer’s demand during the 100 regional peak periods as notified by Transpower. The 100 regional peak periods will be between 1 September 2014 and 31 August 2015 for the Price Year effective 1 April 2017. The OPD is used in calculating the Line Charges of a Consumer on an asset-based load group such as the V40, T50, V60 and T60 load groups.

“Point of Connection” means the point at which electricity may flow between the Network and the Consumer’s Installation and to which an Installation Control Point is allocated.

“Powerco” means Powerco Limited and any of its subsidiaries, successors and assignees.

“Price Category” means the relevant price category selected by the Distributor from this Pricing Schedule to define the Line Charges applicable to a particular ICP.

“Price Year” means the 12-month period between 1 April and 31 March.

“Recoverable Costs” has the meaning specified in clause 3.1.3 of the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

“Region” means the Eastern Region or the Western Region as the case may be.

“Registry” means the Electricity Authority central Registry**.**

“Retailer” means the supplier of electricity to Consumers with installations connected to the Distribution Network.

“Time of Use Meter” (TOU) means metering that measures the electricity consumed for a particular period (usually half-hourly) and complies with Part 10 of the Code.

“Tariff Option” means the price option within a Price Category where such a Price Category provides for Retailer choice amongst two or more options, subject to a particular configuration of metering and Load Control Equipment.

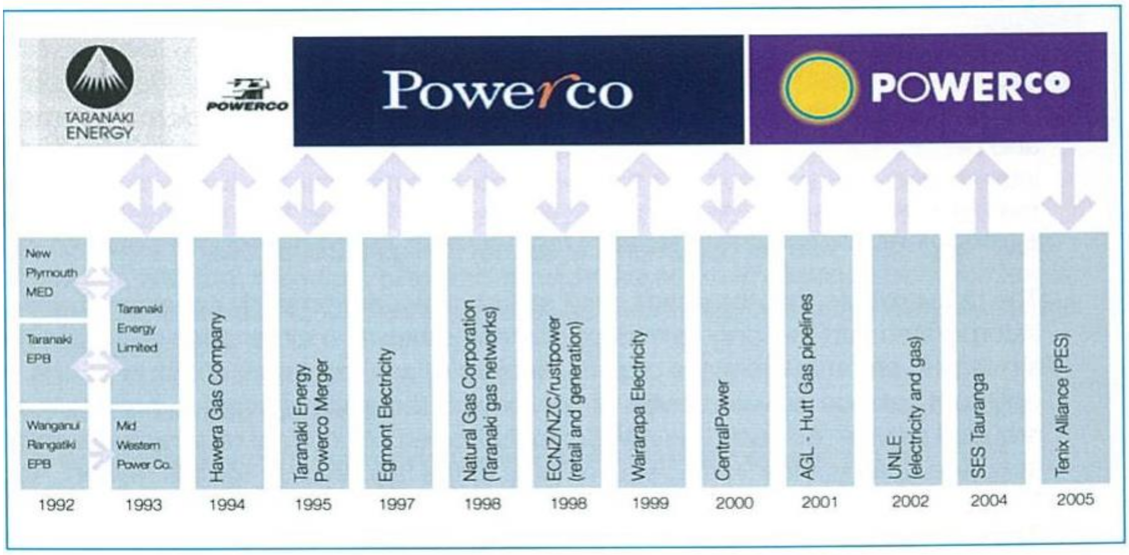
“Transmission Charge” has the meaning specified in section 4 of the Electricity Distribution Services Default Price-Quality Path Determination 2010.

2. BACKGROUND

1. Powerco is a utility network ownership and management business. It is New Zealand's largest provincial distributor of electricity and gas, with around 420,000 consumers connected to its networks. Powerco's electricity networks are located in Tauranga, Thames Valley, Coromandel Peninsula, Eastern and Southern Waikato, Taranaki, Whanganui, Rangitikei, Manawatu and Wairarapa. Our gas pipeline networks are in Hutt Valley, Porirua, Wellington, Horowhenua, Manawatu, Taranaki and Hawke's Bay.

2. From the mid-1990s until the early 2000s, Powerco grew significantly through mergers and acquisitions (see Figure 1). Funds managed by QIC Limited have a 58% stake in Powerco, with the remaining 42% holding owned by AMP Capital Limited.

Figure 1: History of Powerco mergers and acquisitions



3. LEGAL REQUIREMENTS

3. This document contains the information that must be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012*.* Part of this required information is a demonstration of the extent to which the pricing methodology is consistent with the Electricity Authority's pricing principles[4] and, if necessary, an explanation of the reasons for any inconsistency between the pricing methodology and the pricing principles[5]. We do not believe there is any inconsistency between this pricing methodology and the pricing principles.

4. Other legal requirements that affect distribution pricing are contained in the Electricity Distribution Services Default Price-Quality Path Determination 2015 (DPP) and the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004 (Low Fixed Tariff Regulations).

5. Detailed below are:

- the disclosure requirements;

[4] As specified in *Distribution Pricing Principles and Information Disclosure Guidelines*, originally published by the Electricity Commission in March 2010.
[5] Clause 2.4.3(1) of the Electricity Distribution Information Disclosure Determination 2012 refers.

- the Electricity Authority's pricing principles;
- the pricing implications of the DPP;
- the pricing implications of the Low Fixed Tariff Regulations.

ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 – CLAUSES 2.4.1 TO 2.4.5

6. The Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 came into force on 1 October 2012. Clauses 2.4.1 to 2.4.5 of the Determination state:

   Disclosure of pricing methodologies

   2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which—

   (1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;

   (2) Describes any changes in prices and target revenues;

   (3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);

   (4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.

   2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.

   2.4.3 Every disclosure under clause 2.4.1 above must—

   (1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;

   (2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;

   (3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;

   (4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;

   (5) State the consumer groups for whom prices have been set, and describe–

   (a) the rationale for grouping consumers in this way;

   (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;

(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;

(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;

(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.

2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy–

(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;

(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;

(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

2.4.5 Every disclosure under clause 2.4.1 above must–

(1) Describe the approach to setting prices for non-standard contracts, including–

(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;

(b) how the EDB determines whether to use a non-standard contract, including any criteria used;

(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;

(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain-

(a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;

(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;

(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the–

(a) prices; and

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

ELECTRICITY AUTHORITY'S DISTRIBUTION PRICING PRINCIPLES

Pricing Principles		
(a)	Prices are to signal the economic costs of service provision, by:	
	(i)	being subsidy free (equal to or greater than incremental costs, and less than or equal to stand alone costs), except where subsidies arise from compliance with legislation and/or other regulation;
	(ii)	having regard, to the extent practicable, to the level of available service capacity; and
	(iii)	signalling, to the extent practicable, the impact of additional usage on future investment costs.
(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.	
(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 practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.
(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.	
(e)	Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.	

DEFAULT PRICE-QUALITY PATH DETERMINATION – PRICING IMPLICATIONS

7. In November 2014, the Commerce Commission promulgated a starting price adjustment for the 2015-2020 DPP that applies to "non-exempt" electricity distribution businesses[6]. Changes to Powerco's electricity line charges with effect from 1 April 2017 incorporate changes required by this determination.

LOW FIXED TARIFF REGULATIONS – PRICING IMPLICATIONS

8. The Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004 require that, for every residential standard tariff option that is available, another tariff option must also made available for residential consumers for which the fixed charge component is no more than 15 cents per day and the total charges per year for the average residential consumer are the same or no more than those incurred under the standard option. Consequently, changes to the annual charges under the low fixed

[6] The adjustment reset the 2015-20 default price-quality paths for 16 electricity distributors.

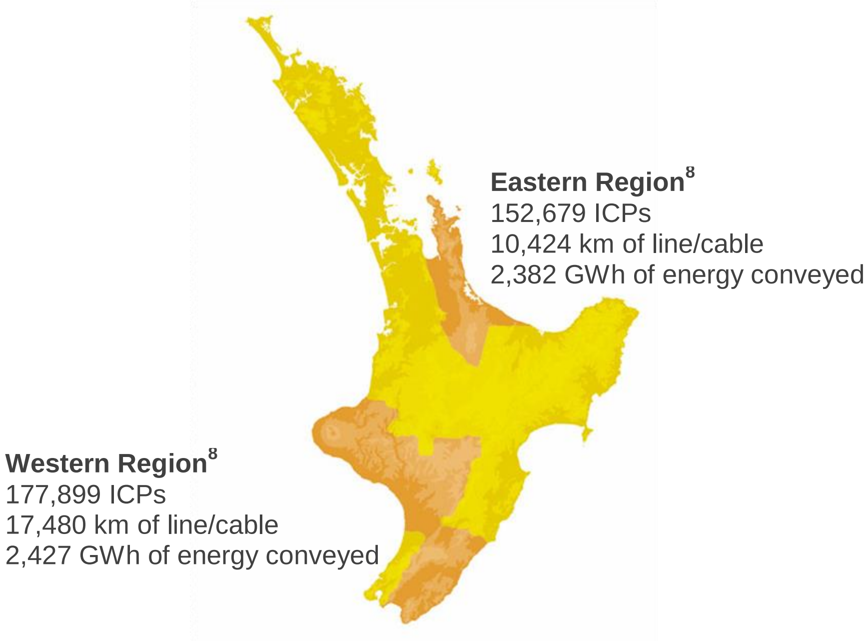
charge option for the average[7] residential consumer must be no more than the changes to the annual charges incurred under the standard option for the same consumer.

4. OVERVIEW OF THE PRICING METHODOLOGY

9. Two different pricing methodologies continue to be used across Powerco's network. The Western Region (as highlighted below) uses a Grid Exit Point (GXP) methodology which can be considered a wholesale delivery model and the Eastern Region uses an Installation Control Point (ICP) methodology which is a retail delivery model. Both methodologies, however, are checked against a cost of supply model developed by Powerco to ensure that prices recover the costs of service provision.

10. These two methods have a number of differences, but the principal difference is the way that quantities for charges are measured.

Figure 2: Map of Powerco's Eastern and Western Regions



OVERVIEW OF THE WESTERN REGION METHODOLOGY

11. A GXP methodology applies in the Western Region covering Taranaki, Wanganui, Rangitikei, Manawatu, Tararua and Wairarapa. The GXP methodology is a wholesale delivery model whereby quantities are derived using reconciled GXP volumes which are then allocated to retailers based on their relevant shares.

12. Powerco uses three price categories in the Western region. The price category E1 is for all residential consumers and most commercial customers, the price category E100 is for commercial customers with installed capacity of 100 kVA or greater (up to and including 300 kVA) and the price category E300 is for commercial customers with installed capacity of greater than 300 kVA. Powerco also has a non-standard

[7] Average consumer is defined as an 8,000 kWh per annum consumer in accordance with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
[8] Figures from Powerco's Electricity Information Disclosure 2015.

SPECIAL price category which is a subset of the E300 price category and is reserved for individual prices charged to major customers (discussed in section 10).

13. These price categories were defined as such due to the different levels of demand that each of these consumer groups place on particular components of the network such as sub-transmission, high voltage (11kV), and low voltage (400V) assets and the on-site assets at each connection. For example, in most cases a mass market (E1) connection makes use of all network assets but has limited on-site assets, whereas an industrial connection in the E300 price category has many more on-site assets but makes limited use of the low voltage (400V) network assets. The use of these consumer groups makes it possible to more accurately recover the costs actually incurred by different classes of customer.

14. Each price category in the Western Region is further differentiated by pricing zones, which reflect groupings of GXPs with similar characteristics such as network density and geographical location. High density networks typically have lower costs per customer than low density networks.

15. Essentially all sales for service take place at the GXP. Volumes and demand data for industrial consumers, normally 11kV network users, are calculated from half hour metering data, adjusted for losses, with the balance of volume and demand inputs derived from the reconciliation process and retailer ICP counts accessed from the industry registry.

16. For the majority of consumers, minimal market segmentation occurs under the GXP method, which should reduce barriers to a competitive retail market and promote innovation in retailer designed consumer tariffs.

OVERVIEW OF THE EASTERN REGION METHODOLOGY

17. An Installation Control Point (ICP) methodology is used for the Eastern Region. While a number of incremental improvements have been made to the pricing structure this methodology has not been significantly altered since the acquisition of the UnitedNetworks (UNL) networks in the Tauranga, Thames Valley and Coromandel regions in 2002.

18. This methodology is a retail delivery model, whereby the sale for service takes place at the consumer’s metering point and, as such, Powerco relies on retailers to provide complete and accurate data in order to derive billable quantities.

19. Powerco has two separate price schedules in the Eastern Region. These different schedules are based on the geographical location of our consumers and the differing network density within each region. These regions are defined as Thames Valley (or Valley, which includes the Coromandel) and Tauranga.

20. Each of these price schedules consists of around six different price categories, again reflecting the tariff structure since the acquisition of the UNL networks in 2002. The price categories are:

    - T01/T02 and V01/V02 − for all unmetered connections in the Valley and Tauranga regions;
    - T05/T06 and V05/V06 − for all residential consumers and small commercial consumers with a fuse size of 3 Phase 60 Amps or less;

- T22/V24 − for commercial customers with a fuse size of greater than 3 Phase 60 Amps up to and including 3 Phase 250 Amps;
- T24/T41/V28 − for commercial customers with an installed capacity of 200 – 299 kVA;
- T43/T50/V40 − for commercial customers with an installed capacity of 300 – 1499 kVA; and
- T60/V60 − for commercial customers with an installed capacity of 1,500 kVA and greater.

21. These price categories were defined around consumer groups with similar load characteristics, such as installation type (such as Unmetered, Non-Half Hour (NHH), and Half Hour (HH)), fuse size and installed capacity of the consumer's installation. Fuse size is used for some price categories, rather than just kVA as in the Western Region, because, for residential and smaller commercial connections, their available capacity is limited by the size of the fuses at their installation rather than the installed capacity of dedicated transformers.

22. The granularity of the groupings for each price category will always be a trade-off between practicality, fairness and cost reflectiveness and, consequently, Powerco has made a number of incremental improvements over the last five years to simplify our tariff structure while limiting rate shocks. Powerco will continue to consult with retailers and consumers to ensure our tariff structures reflect an appropriate balance.

23. This ICP based methodology is more consistent with retailer tariffs and, consequently, makes it possible to provide a greater number of targeted price signals to specific groups or individual market segments of consumers to encourage efficient use of the network.

5. POWERCO'S PRICING STRATEGY

24. Powerco has adopted, in principle, a pricing strategy that involves transitioning the Western Region to ICP-based pricing and introducing differential time-of-use charging to better reflect the long run marginal cost of network use during the daily peak consumption periods. The introduction of these changes is contingent on achieving a penetration of smart meters that exceeds 70% of ICPs.

25. In preparation for these changes Powerco is gathering ICP-based data for the Western Region. Two years' worth of comparative ICP and GXP-based data will be required to demonstrate to the Commerce Commission that new ICP-based charges comply with Powerco's regulated price path.

26. Pricing reform is a complicated process with many potential barriers and issues such as navigating the existing DPP and LFC regulations, deployment of smart metering technology, and managing the retailer and consumer engagement. These issues and many more need to be understood and appropriately addressed prior to implementation.

27. Figure 3 provides Powerco's initial indicative view of the relevant timings associated with the different elements associated with pricing reform. These timings are purely indicative and are subject to change.

Figure 3: Powerco's pricing reform roadmap.

Stage	Activities	Timeline 2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 H1	2018 H2	2019 H1	2019 H2	2020	2021
1. Initiate pricing reform											
Discovery	Undertake, early modelling	X									
Define overall objectives for reform	Set overall goals	X									
Develop strategy to deliver reform	Develop ideas on how to go ahead	X									
Communicate	Prepare and publish future pricing roadmap	X									
Identify challenges	Consider systems, smart meter tech, accessing data, CBA	X									
Establish high level plan	Gain commitment to reform, agree plan, allocate resources		X								
Gather basic data	Survey customers, market analytics, consult peers			X							
Consult retailers	Socialise ideas & plans with retailers			X							
Define pathway	Prepare final strategic pricing plan				X						
Alignment	Compare plan with other EDB's, form coalitions					X					
2. Plan changes in more detail											
Customer interactions	Establish research program and focus groups					X					
Pricing trials to test ideas	Conduct in-market testing					X					
Data analysis to assess customer impacts	Narrow down preferred options and test market impacts						X				
Implementation and transition arrangements	Identify what will drive success						X				
Feedback loops and issues resolution	Develop processes to account for stakeholder views						X				
Communication	Educate customers about change							X			
Regulatory compliance	Check plan meets regulatory expectations							X			
3. Enabling Infrastrucure											
System capability review			X								
Gap analysis				X							
System improvements / updates to support transition										X	
ICP management system								X			
Consumption submission manager									X		
Billing and reconciliation system										X	
4. Manage roll out of new pricing options											
Develop transition strategies	Incentivise and manage take-up over time				X						
TOU pricing trial - stage 2 (Eastern region)	Further TOU trial based on learnings and feedback from stage 1				X						
Review progress and make adjustments	Actively consider progress towards outcomes over time					X					
Implement TOU pricing (Eastern region)	Formerly implement TOU pricing across Eastern region							X			
GXP to ICP transition (Western region)	Transition from GXP to ICP based pricing (Western region)										X
Implement TOU pricing (Western region)	Formerly implement TOU pricing across Western region										X
Ongoing customer interactions	Monitor customer responses and manage as required										X

6. CHANGES TO THE METHODOLOGY / PRICING SCHEDULE

28. The final prices contained in the Pricing Schedule[9] for 2017/18 reflect an average annual increase in charges, in nominal terms, of 1.7%. This increase can be broken down as follows:

- CPI adjustment equivalent to an average price change of 0.3%; and
- pass through of an increase in transmission charges (and other recoverable costs) which adds a further 1.4% (approximately) to the overall price increase.

29. The 1.7% increase does not relate to Powerco's proposed longer term investment levels. For more information on our future investment plans, and the anticipated impact on future charges, please see www.yourenergyfuture.co.nz.

30. The only material change to Powerco's pricing schedule since the previous methodology was published in March 2016 relates to the introduction of a power factor charge in the Western region for the E100/E300 price categories. This standard industry charge was introduced to further align the pricing approaches across both regions and improve the efficiency of our network.

31. Table 1 also details the tariff re-balancing and adjustments to the pricing schedule that have been incorporated from 1 April 2017.

[9] For further details on our prices and how we apply our charges please see the full pricing policy at: http://www.powerco.co.nz/Publications/Pricing-Schedules/Electricity/

Table 1: Summary of tariff rationalisation, adjustments and pricing schedule updates for the 2017/18 financial year

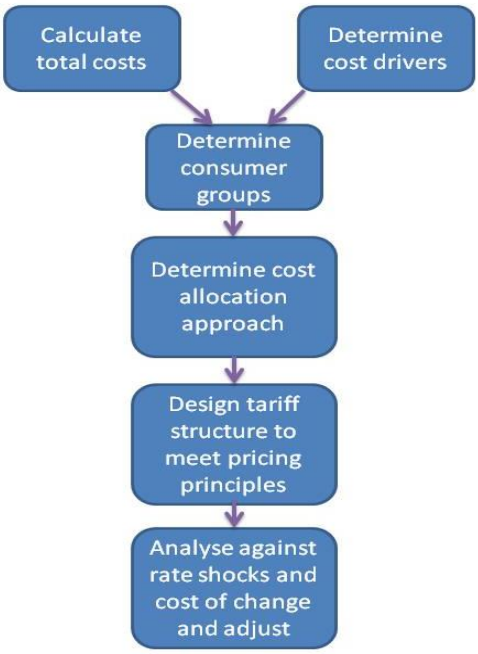
Specific Variation	Materiality	Description
Introduction of Power factor charge for E100/E300 price categories.	High	From 1 April 2017, Powerco will introduce a power factor charge for the 457 customers on the E100 & E300 price categories across the Western region. This new charge is expected to total $138k over the 2017/18 pricing year but the relevant demand charges have been reduced by a similar amount to ensure compliance under the DPP and to minimise the impact to customers at an aggregate level. The power factor charge will be implemented from 1 April 2017 at an initial rate of $1/kVAr /month and we will be transitioning this charge up to the full $7/kVAr/month over the next three years. Retailer feedback strongly supported a gradual introduction of the power factor charge to enable customers to gain an understanding of their particular power factor issues. This approach will also allow customers to have sufficient time to correct any issues before the charge becomes material.
TOU Pricing Trial – Eastern region	Low	For the 2017/18 pricing year Powerco are introducing TOU tariffs in the Eastern region as part of a trial for all mass market consumers. This applies to all customers on the T05/T06 and V05/V06 price categories with advanced metering. This trial is to allow Powerco to test the capability of our systems and processes and to facilitate some R&D initiatives. As such the tariffs and the differentials are subject to change and the trial will be initially limited to 500 customers.
Closure of "All Inclusive" tariff option to new connections	Low	Powerco will be closing the All Inclusive Tariff (AICO) option to all new connections from 1 April 2017. It will still be available for those connections with a meter installed before 1 April 2017 it will, however, not be available for any subsequent meter replacements after this date (as detailed in paragraph 16.5 of the pricing policy).
Non-network Fault Fee	Low	From 1 April 2017 the non-network fee has been increased from $125 to $135 to better reflect the costs Powerco incurs associated with these non-network faults.
Tariff re-balancing for the V24 and V28 price categories.	Medium	From 1 April 2017, Powerco has further reduced the fixed charges for 478 customers in the V24 and V28 price categories. The fixed charges will change from $9.92 and $45.19/day to $9.80 and $40.32/day with an appropriate uplift in the associated variable charges to partially mitigate the decrease in fixed charge revenue. Powerco will continue to reduce the fixed charge for this consumer group in future years until it is aligned to the equivalent charges in the Tauranga region.
Customer migration from "T43" to "T50" price category continues.	Low	In April 2013 Powerco instigated an initiative to progressively migrate all T43 connections to T50 Asset Based Pricing. This migration is being performed to allow the application of more cost reflective tariffs to these consumers and will also allow the eventual closure of the legacy T43 price category. From 1 April 2017, this initiative is continuing by migrating a further three customers from T43 to the T50 price category. This will result in an estimated $0.1m of additional fixed charge revenue for the T50 price category which is offset by an associated decrease in variable charge revenue for the T43 price category. Powerco intend to continue with the migration of the remaining seven sites from T43 to T50 in future years, when existing sites review their assets, and as customers vacate.

32. All the changes outlined in the table above were discussed in detail with retailers during two rounds of consultation before being implemented. In all cases we have chosen the relevant course of action in collaboration with retailers. When we confirmed our approach during our draft pricing notification no feedback was received suggesting that our approach was inappropriate and therefore no alternative approaches were considered.

7. SUMMARY OF PRICING PROCESS

33. The pricing process is summarised in Figure 4.

Figure 4: Overview of the pricing process



34. A description of the pricing process is:

- calculate total costs for the relevant period; these include transmission costs (including ACOT), capital costs, operating costs, maintenance costs and administration costs;
- determine the key drivers of network expenditure;
- determine suitable groupings of connections across each network based on similarities of network and consumer characteristics such as geography, rural/urban connection density, mains size, protection rating and/or transformer capacity;
- determine the allocation of costs (such as operating costs, transmission costs and cost of capital) across each network and tariff category;
- calculate prices based on the relevant cost allocations, ensuring compliance with the relevant legal requirements;
- assess the pricing structure to take account of the effect of rate shocks and adjust as needed.

8. QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

35. The key components of network costs and revenue for Powerco's Eastern and Western Regions are summarised below. Network assets, customer density and system length largely drive these costs. Consequently, these costs are largely fixed and independent of the volume of electricity consumed across our network.

OPERATING COSTS

36. These are costs associated with the provision of electricity distribution services, including:

- statutory charges and levies (excluding those that are pass through costs);
- network planning and asset management costs;
- network management and dispatch costs;
- network operation costs;
- the cost of support services such as billing, record management, planning, contract administration, regulatory compliance and resource costs;
- depreciation on electricity lines business assets; and
- tax.

37. Detailed information on Powerco's historical costs are disclosed each year in Powerco's annual information disclosure to the Commerce Commission. This information is publicly disclosed on Powerco's website, including by cost category.

38. Powerco's Asset Management Plan contains forecasts of capital and operating expenditure over a ten year period which helps to form a view of future costs. This information is also publicly disclosed on Powerco's website.

39. Powerco's operating costs relating to the electricity business are allocated directly to each relevant region. Where this is not possible, the allocation between regions is based on each region's total optimised replacement cost (ORC), due to the assumption that, over time, operating costs within a region are likely to be broadly proportional to the initial cost of the assets within each region.

40. Powerco's indirect operating costs relating to the electricity business are allocated between regions and customer groups using a weighted average of each group's contribution to system demand and ICP numbers. These costs are shared equally by all users, but the weighting recognises the contributions larger consumers make to these costs.

TRANSMISSION COSTS

41. These are the costs charged by Transpower for transmission services and those charged by other parties that provide services that substitute for transmission or distribution services. Transmission costs include Transpower's interconnection, connection and new investment charges and any avoided cost of transmission (ACOT) payments made by Powerco.

42. Transmission costs are allocated between customer groups using a weighted average of the regional coincident maximum demand (based on the 100 regional coincident

peak demands) attributable to each load group and the number of ICPs within each load group. This is because Transpower's interconnection charges, which represent the major part of Powerco's transmission charges, are directly related to these regional coincident peak demands.

COST OF CAPITAL

43. This is the cost of capital (both debt and equity) invested in Powerco. Powerco requires large amounts of capital to maintain and develop network assets to meet increased demand, satisfy quality standards and legal compliance requirements, and achieve performance targets for safety and reliability. Historical capital expenditure by drivers (e.g. system growth, replacement and renewal) is available on Powerco's website.

44. Powerco's asset management plan provides a large amount of detail on the drivers of capital expenditure for the network.[10]

45. Capital costs are allocated between regions based on the estimated optimised depreciated replacement cost of the assets within each group.

SUMMARY OF KEY COMPONENTS OF TARGET REVENUE

Table 2: The numerical value of each of the key components of Powerco's target revenue for the 2017/18 financial year

Key Component	Eastern Region ($000)	Western Region ($000)	Total Network ($000)
Operating and maintenance costs	64,012	77,317	**141,329**
Transmission charges[11]	62,947	61,103	**124,050**
Cost of Capital	58,506	66,254	**124,760**
Total	**185,465**	**204,674**	**390,139**

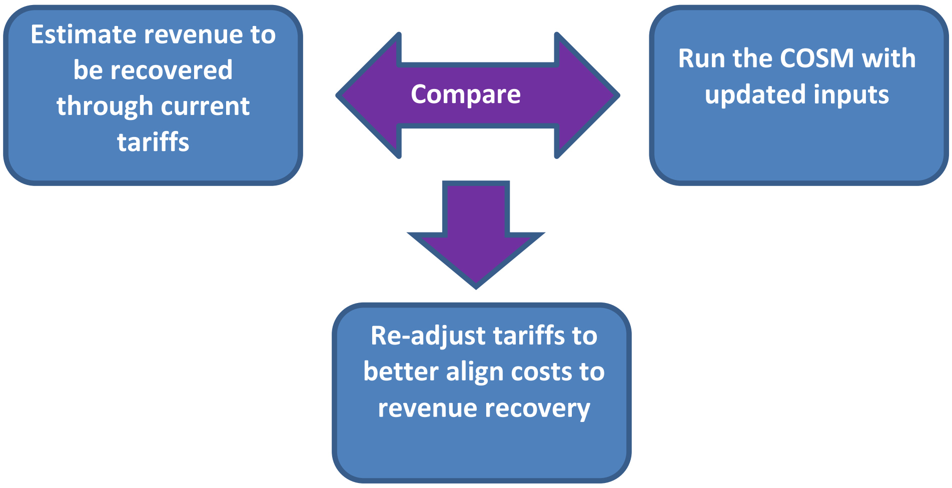
9. THE ROLE OF THE COST OF SUPPLY MODEL IN SETTING PRICES

46. Powerco uses a cost of supply model (COSM) to allocate three broad categories of cost: transmission costs, operating and maintenance costs, and capital costs. The role of the COSM is not to set prices, but rather to evaluate how current tariff structures recover different categories of cost. This process of verifying tariffs through the COSM is used for both the Western and Eastern regions. If the results of the COSM are significantly different from the revenues recovered through existing prices, prices are adjusted to ensure a better alignment of revenues and costs.

[10] Section 9 of Powerco's 2013 Asset Management Plan, available at www.powerco.co.nz.
[11] Transmission costs include Transpower's charges and avoided costs of transmission (ACOT).

47. Powerco's cost allocation can be summed up in three steps. First, prices used in the previous pricing year are adjusted to reflect the overall revenue requirement. The COSM is then run and its results compared to the revenues generated by the updated set of prices. If changes are required, prices are readjusted by applying discretion while aiming to maintain price stability and minimise price shocks to the extent practicable. Figure 5 below illustrates this process.

Figure 5: Cost allocation process and the COSM's role



48. The COSM uses a number of key inputs and cost drivers to determine the appropriate allocation of costs between the relevant consumer groups. The key allocators contained within this model are:

- average number of connected ICPs;
- coincident maximum demand (CMD);
- installed kVA;
- optimised depreciated replacement cost (ODRC);
- contribution to system demand and ICP numbers, which is used in the determination of GXP cost allocation; and
- contribution to coincident maximum demand and ICP numbers, which is used in the allocation of costs between load groups.

49. For the purposes of cost allocation, the COSM aggregates costs into one of three customer groups. These three groups align with the Western Region's customer groups. With respect to the Eastern Region, the customer groups in the COSM do not directly align with the customer groups used for pricing in the methodology that Powerco inherited from UNL (and continues to apply). However, the results of the COSM can be made compatible with the Eastern Region's pricing groups by collapsing the seven customer groups used for pricing into three broader groups.

50. The three groups used in each region are presented in the table below. Although some minor differences between the two regions exist, the three groups used in each region are essentially the same.

Table 3: Consumer groups used by the COSM

Groups	Eastern Region	Western Region
Residential	**Mass Market.** Includes unmetered, residential and small commercial consumer groups	**E1.** All residential and most commercial consumers including unmetered connections
Commercial	**Commercial.** Capacity greater than 69 kVA but less than 299 kVA	**E100.** Includes all connections with an installed capacity of greater than 100 kVA up to 300 kVA
Larger customers	**Larger customers.** Capacity greater than or equal to 300 kVA (this includes individually priced consumers in the V40, T50, V60 and T60 groups)	**E300.** Includes all connections with an installed capacity of greater than 300 kVA, including non-standard connections

51. Where possible, the costs of operating Powerco's electricity business are allocated directly to each region. Where direct allocation is not possible, each region is allocated costs based on the optimised replacement cost (ORC) of assets.

52. Transmission costs are allocated directly to each region because costs are directly attributed to specific GXPs. Capital costs are allocated to regions based on the optimised depreciated replacement cost (ODRC) of the assets within each group.

53. Powerco's operating costs, transmission costs and capital costs are then subsequently allocated between price categories using a 80:20 weighted average of the contribution to regional coincident peak demand and ICP numbers for each group in accordance with the formula below:

$$A_i = \frac{(0.8D_i + 0.2I_i)}{\sum_1^n (0.8D_i + 0.2I_i)}$$

where *A* is the cost allocator;

I is the number of ICPs for each price category *i*;

D is the contribution to regional coincident peak demand for each price category *i*.

54. The resulting cost allocations by region and consumer groups are then compared to the historical revenue for each consumer group to identify any potential material variances. If the results of the COSM are significantly different to the existing revenues recovered through existing prices, then prices are adjusted appropriately to achieve a better alignment of revenues and costs.

10. CUSTOMER-SPECIFIC PRICING

ASSET-BASED PRICING METHOD

55. This pricing method applies to large Powerco consumers in both the Eastern and Western Regions and others that opt for an asset-based price. Asset-based pricing may also apply to generation connections and special arrangements designed to mitigate the risk of asset bypass.

56. The methodology for setting line charges under asset-based pricing has the following components:
    - measurement of consumer demand;
    - asset valuation and allocation;
    - return of and on capital;
    - allocation of maintenance costs; and
    - allocation of indirect costs (fixed and variable).

57. Asset-based charges to consumers are allocated on the basis of a full price year and apply for the full price year. Charges are based on customers' level of demand, measured by AMD (anytime maximum demand) or OPD (on peak demand).

58. The asset-related element of the charge requires the assets used to supply the service to be valued, using either the ORC or ODRC methods. Whether the ORC or ODRC methodology is adopted depends on the consumer load group. For load groups T50 and V40 the ODRC methodology is used. For load groups T60 and V60 the ORC methodology is used.

59. Asset-based pricing requires assets to be categorised as on-site assets or upstream assets, viz.:
    (a) on-site assets are dedicated assets behind the point of connection and normally include transformers and switch gear. These assets are allocated fully to the consumer that uses them;
    (b) upstream assets are the meshed assets of the network. These assets are shared between a number of consumers and can generally be categorised as feeder assets, substation assets, sub-transmission assets and grid exit point (GXP) assets. These assets are allocated across the consumers they serve.

60. Powerco's charges are calculated to enable it to obtain a return on the capital it has invested. An annual rate of return is recovered on the asset valuations attributed to each consumer – this is based on Powerco's prevailing weighted average cost of capital (WACC). For those assets valued using ORC, Powerco uses a 45 year annuity factor to obtain a return of and on the capital it has invested (as measured by ORC). For those assets valued using ODRC, Powerco applies the WACC-based rate of return to the ODRC values to obtain a return on its capital invested, and uses a straight-line depreciation charge to obtain a return of its capital.

61. Maintenance costs are allocated to the relevant load groups (T50 and V40) based on the load group's ODV relative to the applicable GXP's total ODV. These costs are allocated among the consumers within the load group based on each consumer's AMD as a proportion of the aggregate AMD of the load group.

62. Indirect costs are all costs of Powerco's electricity business excluding transmission, asset-related costs, maintenance, interest and tax. Indirect costs are allocated to the load group based on the load group's total ODV as a proportion of the applicable GXP's total ODV. Seventy per cent of the charges are recovered as a fixed equal charge to each consumer in the load group. The remaining thirty per cent of the charges are recovered based on the consumer's OPD (as measured using Transpower's methodology) relative to the aggregated OPD of the load group at each GXP.

63. Powerco's transmission service charges are based on Transpower's charges, which it determines using its transmission pricing methodology (TPM), which is set out in

Schedule 12.4 of the Electricity Industry Participation Code 2010. The TPM is used to recover the full economic costs of Transpower's services. Transpower charges Powerco at each GXP using the TPM. The TPM includes connection and interconnection charges. Powerco allocates these charges in the following manner:

(a) Connection charges: Powerco allocates Transpower's connection charges on the basis of the consumer's demand measured by AMD. Where a consumer is both an offtake consumer and an injection consumer at a connection location, connection charges for that location are calculated separately for that consumer as an offtake consumer and an injection consumer. Powerco also allocates charges from embedded generators to its consumers. This charge includes a connection charge and an ACOT charge. These charges are allocated by Powerco to its consumers on the same basis that Powerco uses to allocate Transpower's connection and interconnection charges.

(b) Interconnection charges: Powerco allocates Transpower's interconnection charges to its customers based on the consumer's OPD multiplied by Transpower's interconnection rate.

64. When a Powerco consumer enters an asset-based load group the following policies apply:

- Powerco will estimate the OPD and AMD for the new or upgraded site. This estimate will be based on an assessment of the plant and machinery located on the site, demand from similar sites across the industry and any estimates of demand provided by the consumer.
- The estimated demand will apply for the current price year (i.e. the period between the later of 1 April or the connection date for the upgraded assets and 31 March of the subsequent year).
- The estimated demand will assume full demand from the time of the installation of the asset (rather than ramping up over a period of time), unless otherwise agreed between Powerco and the consumer, or their representative, at the time of Powerco's approval of the request for site connection or alteration.
- The estimated demand will continue to apply in the subsequent year if the upgraded site has not been connected and operational for the full duration of the applicable measurement period, unless otherwise agreed between Powerco and the consumer or their representative, at the time Powerco approves the request for site connection or alteration.
- New prices will be effective from network livening (i.e. "ready" status).

65. The following Powerco policies apply when a site exits an asset-based load group or revision to charges is requested:

- If a consumer intends exiting a site, and the retailer is notified of this intention, the retailer must notify Powerco as soon as practical so that final charges can be determined and levied in the forthcoming billing run.
- Powerco, at its discretion, may allow a consumer to exit the load group when the site downgrades its installed capacity. Alternatively, Powerco may require the site to continue to the end of the price year in the current load group at the current peaks, for instance if an upgrade to the site has only recently occurred.
- Powerco may leave the consumer in the same load group and down-grade peak estimates in instances where there is no removal of on-site assets but there will be a reduction in loading on the network.
- Where there is a bona fide change in consumer at particular premises (i.e. a new entity), the retailer may apply for, and Powerco will, at its discretion, undertake a

review of the asset-based charges once during the price year to reflect the change arising from an alteration in AMD and the expected change in OPD.

ASSET-BASED "BUILDING BLOCK" METHOD (BBM)

66. This pricing methodology applies to very large (>4MVA) customers in both regions. These customers have a direct contractual relationship with Powerco for a defined term. BBM asset-based pricing applies primarily to customers where:
    - a step change development is needed but the increase in the customer's demand may not be as significant; and/or
    - a new customer connection is required that involves significant investment.

67. BBM asset-based pricing comprises the following input components:
    - return on capital investment, plus accounting depreciation in period or year;
    - sub-transmission cost allocation of direct and indirect costs for sub-transmission asset utilisation in period or year;
    - operating and maintenance costs;
    - tax adjustment; and
    - recovery of pass-through costs and recoverable costs (e.g. transmission charges and regulator levies).

11. THE TREATMENT OF CAPITAL CONTRIBUTIONS

68. Powerco's electricity network is constantly growing as new homes and businesses connect to its network, and existing consumers require new assets as their electricity demand increases. To be fair to our current electricity consumers, who are not increasing their load, we sometimes require a contribution to the capital cost of investments.

69. When an application is received to connect to Powerco's network, or install additional capacity, Powerco's Customer Works team will determine the level of customer contribution required (if any) based on:
    a) the degree to which the incremental revenue received from the new customer or the additional assets installed to upgrade service to an existing customer will enable Powerco to receive a commercial return on the investment, taking into account:
        - the marginal increase in operating and maintenance costs;
        - the marginal increase in overhead costs; and
        - the marginal increase in transmission costs (applicable to the electricity network only);
    b) the value of any deferral of renewal expenditure that results from the early replacement of existing assets due to customer initiated work;
    c) the application of an avoidable cost allocation methodology to identify and allocate incremental costs.

70. Any capital contributions received do not form part of Powerco's regulated asset base and no return on the value of these contributions is recovered by Powerco's charges.

71. Further information on Powerco's capital contribution policy is available at: http://www.powerco.co.nz/uploaded_files/Publications-and-Disclosures/New/Disclosures/Electricity-Capital-Contribution-Guide-vF.pdf.

12. EASTERN REGION PRICING METHODOLOGY

CONSUMER GROUPS

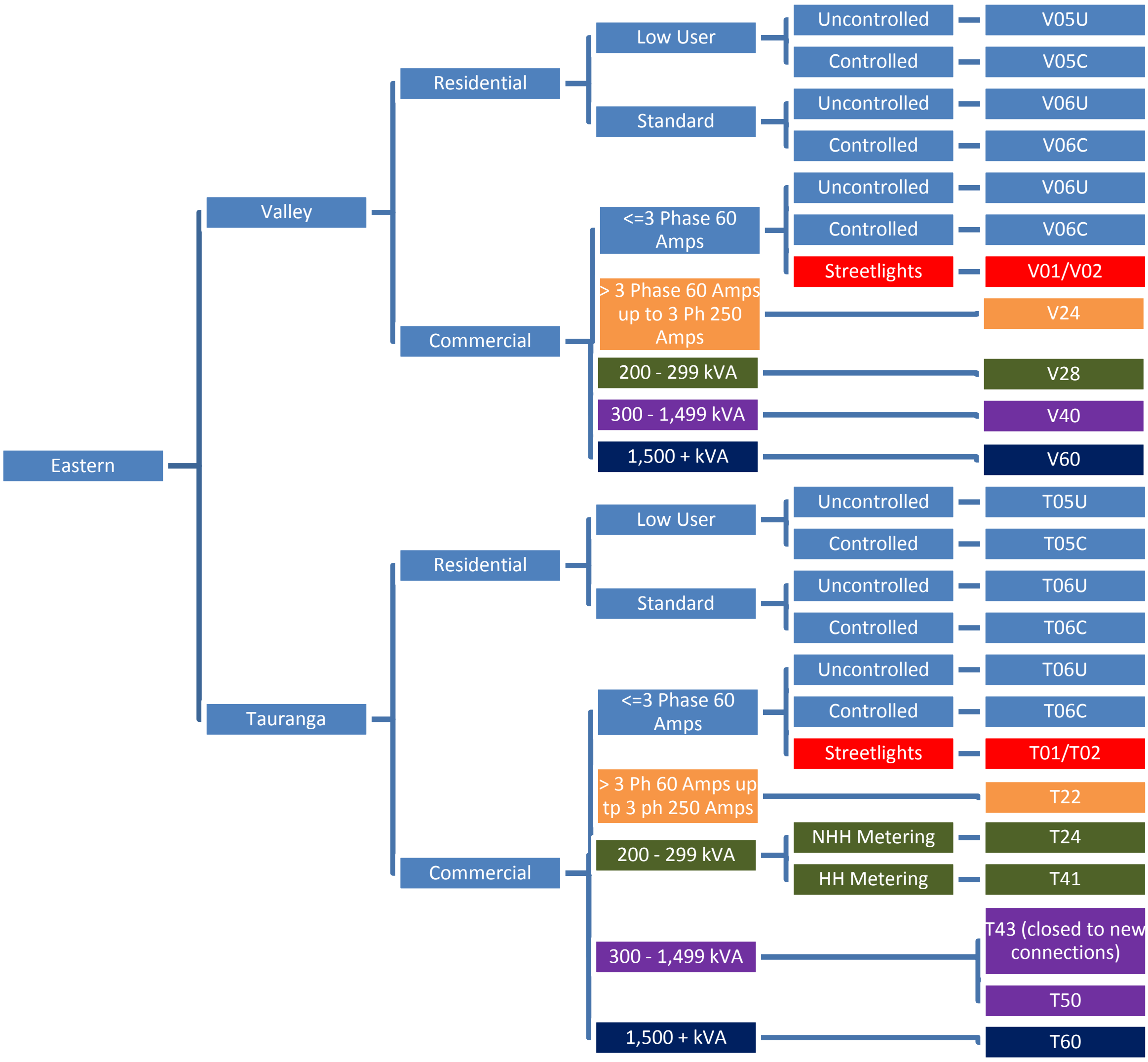
RATIONALE FOR CONSUMER GROUPS

72. Powerco uses six consumer groups in the Eastern Region for pricing purposes:

- Group 1: T01/T02 and V01/V02 − for all unmetered connections such as streetlights in the Valley and Tauranga regions;
- Group 2: T05/T06 and V05/V06 − for all residential consumers and small commercial consumers with a fuse size of 3 Phase 60 Amps or less;
- Group 3: T22/V24 − for commercial customers with a fuse size of greater than 3 Phase 60 Amps up to and including 3 Phase 250 Amps;
- Group 4: T24/T41/V28 − for commercial customers with an installed capacity of 200 – 299 kVA;
- Group 5: T43/T50/V40 − for commercial customers with an installed capacity of 300 – 1499 kVA; and
- Group 6: T60/V60 − for commercial customers with an installed capacity of 1,500 kVA and greater.

Note that Group 5 and Group 6 together equate to the Western region's E300 consumer group.

Figure 6: Overview of the Eastern Region price category allocation process



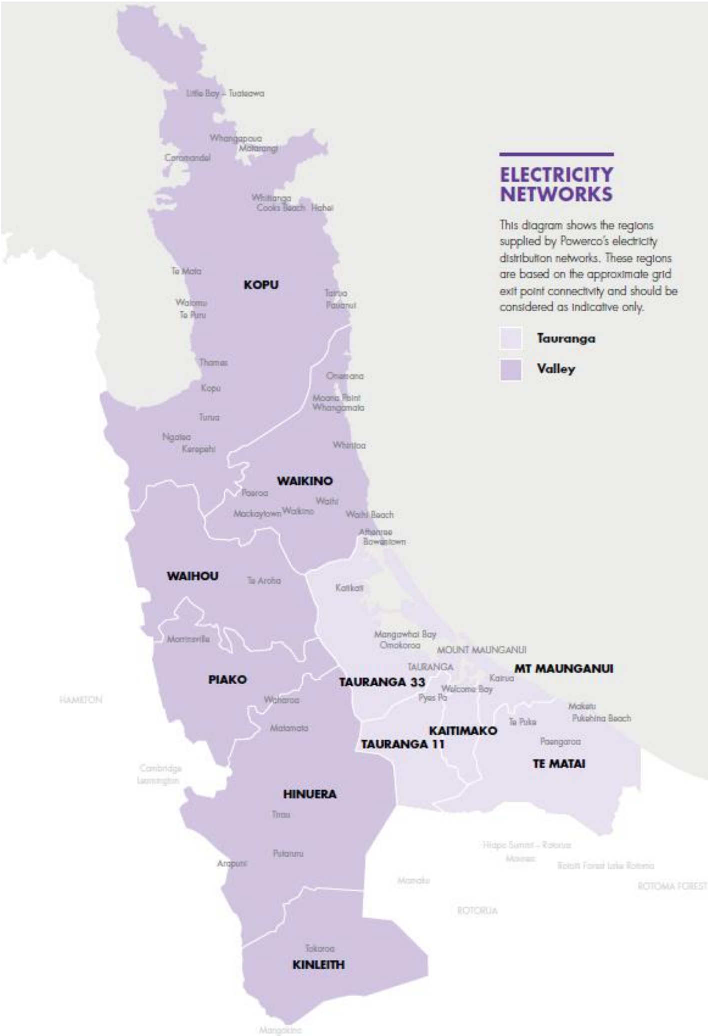
	Residential / small commercial		Unmetered load
	Greater than 3 Ph 60 amps up to 3 Ph 250 amps		200 - 299 kVA
	300 - 1,499 kVA		1,500 kVA and above

73. Figure 6 above shows how separate price categories are defined in the Eastern Region that group consumers with similar load characteristics, such as demand, fuse size and installed capacity, as well as those which use specific sets of assets. Fuse size is used for some categories, rather than simply kVA, as in the Western Region, because, for residential and smaller commercial connections, their available capacity is limited by the size of the fuses at their installation rather than the installed capacity of dedicated transformers. For this reason connections typically have only one applicable price category, but there are situations where consumer preferences and metering can determine the price category (such as the low user (V05/T05) and the T24/T41 price categories).

74. Eastern Region consumers are also allocated to either the Valley or Tauranga distribution networks, based on the location of the GXP that is associated with the consumer's ICP (as shown in Figure 7). Once allocated, the price categories are

published for each ICP on the Electricity Registry[12] to enable retailers and other parties to determine the distribution charges that apply to that ICP.

Figure 7: Map of Eastern Electricity Network



75. Table 4 describes the statistical characteristics of each consumer group and demonstrates that average volume and average anytime maximum and on peak demands are quite different for each group. Information about anytime maximum demand and on peak demand is currently only available for connections that have half hour meters. Consequently, assumptions must be made to estimate the load profiles of the remaining consumer connections. Where appropriate, this is done by using the average demand/kWh for all connections in the particular consumer group or, in the case of the residential and small commercial consumer groups, by subtraction. As smart meters become more widely used, additional peak demand information will become available for mass market customers.

[12] https://www.electricityregistry.co.nz

Table 4: Statistics for Eastern Region consumer groups used in the pricing methodology

Region	Consumer Group	ICPs	Volume (MWh)	Anytime Maximum Demand (kW)	On Peak Demand (kW)
Tauranga	Unmetered Streetlights	227	2,414		
	Residential & Small Commercial	80,344	604,162		
	3 Phase 100 Amps up to and including 3 Phase 250 Amps	508	46,921	18,681	8,424
	200 - 299 kVA	145	34,827	11,786	4,946
	300 - 1,499 kVA	201	184,346	52,478	24,106
	1,500 kVA +	28	113,812	40,132	18,642
	Total	**81,453**	**986,481**	**123,077**	**56,117**
Valley	Unmetered Streetlights	191	666		
	Residential & Small Commercial	69,655	549,483		
	3 Phase 100 Amps up to and including 3 Phase 250 Amps	442	58,681	16,713	7,563
	200 - 299 kVA	38	8,038	2,643	1,179
	300 - 1,499 kVA	78	52,106	18,209	6,974
	1,500 kVA +	29	612,591	142,517	62,731
	Total	**70,433**	**1,281,566**	**180,082**	**78,447**

*Demand figures for any non-half hourly connections in these consumer groups have been estimated using the average demand/kWh for all connections in that particular consumer group.

76. The T01/T02 and V01/V02 price categories (coloured red in figure 5) are for unmetered streetlights which, due to the unmetered nature of the load and the associated dedicated equipment, require special consideration when determining our revenue requirement.

77. The T05/T06 and V05/V06 price categories (coloured light blue in figure 5) are for all residential consumers and small commercial consumers with a fuse size of 3 Phase 60 amps or less. Any consumers with a fuse size of up to 3 Phase 60 Amps are typically considered to be residential or small commercial consumers and, as such, individually place minimal demands on our network and require minimal investment in on-site and upstream assets. Providing specific eligibility criteria[13] are met, residential consumers can choose between the low user price categories (V05/T05) and the standard price categories (V06/T06).

[13] For details on the eligibility criteria for the low user (also known as low fixed charge) prices please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

78. The T22/V24 price categories (coloured light brown in figure 5) are for connections with a fuse size of greater than 3 Phase 60 amps up to 250 amps. Any connections with these fuse sizes are typically commercial consumers with higher average volumes than the T05/T06 and V05/V06 price categories. Therefore, this group places increased demands on different components of our network and requires a slightly larger investment in on-site and upstream assets.

79. The T24/T41/V28 price categories (coloured green in figure 5) are for connections with an installed capacity of greater than 200 kVA up to 299 kVA. Any connections with this level of installed capacity are typically medium sized commercial consumers with significantly higher average volumes than the T22/V24 price categories. Therefore, this group places increased demands on the upstream network assets and requires a slightly larger investment in on-site and upstream assets. The T41 price category is available only for connections in this consumer group with half hourly (HH) metering.

80. The T43/T50/V40 price categories (coloured purple in figure 5) are for connections with an installed capacity of greater than 300 kVA up to 1,499 kVA. Any connections with this level of installed capacity are typically large commercial consumers which require dedicated transformers and associated switch gear to meet their supply requirements. The T43 price category is a legacy price category and as such is closed to new connections.

81. The T60/V60 price categories (coloured dark blue in figure 5) are for connections with an installed capacity of greater than 1,500 kVA. Any connections with this level of installed capacity are typically very large commercial/industrial consumers which place increased demand on upstream network assets and require dedicated on-site transformers and dedicated feeders to meet their supply requirements.

82. Because connections in the V40, T50, T60 and V60 price categories typically require dedicated on-site and upstream assets they are all individually priced based on their specific on-site and upstream assets and contribution to peak demands. While these consumers are charged a constant daily rate this rate is reviewed each year based on the consumer’s previous year’s peak demands (as detailed in paragraphs 55 – 65). This ensures that their charges are regularly updated to reflect their individual contribution to network costs.

83. The ICP pricing methodology more closely reflects retailer tariffs and consequently makes it possible to provide a greater number of targeted price signals to specific groups or individual consumer market segments to encourage efficient use of the network.

84. Powerco’s charges are structured so that the fixed revenue component increases as the connected capacity of each price category increases. This is to help ensure that our overall charges reflect the level of demand that consumers place on different components of our network such as sub-transmission, high voltage (11kV) and low voltage (400V).

85. The granularity of the groupings for each price category will always be a trade-off between practicality, fairness and cost reflectiveness and Powerco will continue to consult with retailers and consumers to strike the preferred balance between these objectives.

COST ALLOCATION METHODOLOGY

86. Since the acquisition of the network from UNL in 2002, Powerco has maintained an ICP based pricing methodology. Although some incremental changes to the methodology have been made, the methodology remains materially the same. This is in response to the high priority that consumers and retailers place on price stability. As described above, Powerco uses the COSM to confirm that the allocation of costs that results from current tariffs broadly aligns with the costs incurred by Powerco. Where significant differences exist, then tariffs are adjusted.

87. Tables 5 and 6 provide a summary of the statistics and the allocation factors used in the COSM to allocate costs between regions and price categories for the Eastern Region.

Table 5: Summary of the statistics used to allocate the costs of Powerco's lines business activities by key revenue components to each consumer group for the relevant financial year

EASTERN REGION							
Distribution network	Consumer Group	Allocator for:					
		ICPs	RCPDs (kW)	LV Asset Value ($000)	HV Asset Value ($000)	Total Asset Value ($000)
Tauranga	Mass market (Including Unmetered ICPs)	80,571	135,672	77,268	176,172	**253,441**
	69 – 299 kVA	653	13,369		17,561	**17,561**
	300 kVA + (including non-standard consumers)	229	42,748		58,566	**58,566**
Valley	Mass market (including unmetered ICPs)	69,846	113,461	80,183	193,003	**273,186**
	69 – 299 kVA	480	8,742		13,780	**13,780**
	300 kVA + (including non-standard consumers)	107	69,705		80,621	**80,621**
Total		**151,886**	**383,696**	**157,451**	**539,704**	**697,155**

Table 6: Summary of the factors used to allocate the costs of Powerco's lines business activities by key revenue components to each consumer group for the relevant financial year

EASTERN REGION				
Distribution network	Consumer Group	Allocator for:		
		Operating Costs	Transmission Costs	Cost of Capital
Tauranga	Mass market (Including Unmetered ICPs)	35%	31%	36%
	69 – 299 kVA	3%	4%	3%
	300 kVA + (including non-standard consumers)	9%	12%	8%
Valley	Mass market (including unmetered ICPs)	41%	30%	39%
	69 – 299 kVA	2%	3%	2%
	300 kVA + (including non-standard consumers)	11%	20%	12%

QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

88. The key components of costs and revenues are described in paragraphs 35 - 45. The breakdown of these costs into consumer groups is provided in Table 7.

Table 7: Powerco's allocated revenue requirement for the 2017/18 financial year by consumer group

EASTERN REGION							
Distribution network	**Consumer Group**	**ICPs**	**Revenue required for:**				
			Operating Costs $(000s)	**Transmission $(000s)**	**Cost of Capital $(000s)**	**Total $(000s)**
Tauranga	Mass market (incl Unmetered ICPs)	80,571	22,121	19,589	20,693	**62,403**
	69 – 299 kVA	653	1,725	2,370	1,434	**5,529**
	300 kVA +	228	5,459	7,301	4,740	**17,500**
	Non-standard	1	51	124	42	**217**
Valley	Mass market (incl. unmetered ICPs)	69,846	25,970	19,093	22,307	**67,369**
	69 – 299 kVA	480	1,416	1,811	1,125	**4,353**
	300 kVA +	100	4,914	4,645	4,449	**14,008**
	Non-Standard	7	2,356	8,013	2,134	**12,503**
Total		**151,886**	**64,012**	**62,947**	**56,924**	**183,883**

FIXED AND VARIABLE CHARGES

89. In Powerco's Eastern region consumers are typically charged a two-part tariff which consists of a variable (cents/kWh) tariff and a fixed charge ($/day). The only exceptions are the V40, T50, V60, and T60 price categories where the tariffs consist primarily of fixed charges.

90. Consumers in the V40, T50, V60, and T60 price categories are typically very large commercial/industrial consumers which require dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. Therefore, their charges are determined on an individual basis and are fixed to ensure that an appropriate level of return on investment is made by Powerco.

91. From an economic point of view, a two-part tariff should ideally be structured such that all marginal costs are charged based on a variable basis and all other costs on a fixed

basis (so as not to distort behaviour). However, marginal costs are typically small (zero if spare capacity exists) which would result in the majority of charges being fixed.

92. However, an economically pure single fixed charge would not provide consumers with any incentive to manage their consumption and therefore would likely result in substantial growth which would put increased pressure on our network and increase the need for future capital expenditure. A high fixed charge would also act as a significant deterrent to existing and potential customers.

93. Powerco wishes both to promote the economically efficient use of our network and encourage organic growth. Therefore our charges are designed to allow end-consumers the opportunity to modify their behaviour to enable the efficient use of network assets. The roll out of advanced metering infrastructure should allow us, in future, to send a more efficient price signal based on peak period time of use, rather than solely volume as at present. Implementing such a change is part of Powerco's medium-term pricing strategy.

94. Powerco's tariff structure in the Eastern Region has been designed so that connections with higher connected capacity have a higher fixed component than connections with lower connected capacity. This benefits both Powerco and its customers by making charges more predictable and more closely related to the actual cost of supply.

95. This approach also helps to ensure that no perverse incentives exist for customers to under or over state their capacity requirements in order to alter their allocated load group. The larger capacity price categories have the bulk of the charges fixed, while lower capacity connections have the fixed component set at around 25% of their total line charge (as shown in Table 8).

96. However, Powerco's ability to amend the existing fixed and variable rate structure is somewhat restricted by the limitations imposed on residential fixed charges by the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004, the constraint imposed on total revenue by the Electricity Distribution Services Price-Quality Path Determination 2015 and Powerco's own policy of avoiding price shocks to end-consumers. Consequently, Powerco determines the proportion of fixed and variable charges by reference to existing rates while recognising the largely fixed nature of the underlying costs. The regulations have a large influence on the level of the fixed and variable components for residential groups.

Table 8: Powerco's target revenue requirement split by fixed and variable charge components to each consumer group for the relevant financial year

	EASTERN REGION			
Distribution network	**Consumer Group**	**Price Category**	**Revenue split**	
			Fixed	**Variable[14]**
Tauranga	Mass market (Including Unmetered ICPs)	Unmetered (T01/T02)	74.3%	25.7%
		Low Usage (T05U/T05C)	9.8%	90.2%
		Standard (T06U/T06C)	27.0%	73.0%

14 Including power factor charges (where applicable).

	EASTERN REGION			
Distribution network	**Consumer Group**	**Price Category**	**Revenue split**	
			Fixed	**Variable**[14]
	69 – 299 kVA	3 Phase 60 – 3 Phase 250 Amps (T22)	33.5%	66.5%
		200 – 299 kVA (T24)	57.3%	42.7%
		200 – 299 kVA (T41)	22.9%	77.1%
	300 kVA + (incl. non-standard consumers)	300 – 1,499 kVA (T43)	39.0%	61.0%
		300 – 1,499 kVA (T50)	96.7%	3.3%
		1,500 kVA + (T60)	96.2%	3.8%
Valley	Mass market (including unmetered ICPs)	Unmetered (V01/V02)	90.0%	10.0%
		Low Usage (V05U/V05C)	9.8%	90.2%
		Standard (V06U/V06C)	25.3%	74.7%
	69 – 299 kVA	3 Phase 60 – 3 Phase 250 Amps (V24)	29.3%	70.7%
		200 – 299 kVA (V28)	50.7%	49.3%
	300 kVA + (incl. non-standard consumers)	300 – 1,499 kVA (V40)	96.6%	3.4%
		1,500 kVA + (V60)	98.8%	1.2%

TREATMENT OF RENTAL REBATES

97. Transpower's rental rebates associated with operation of its HVAC network are excluded from the bundled tariffs and are passed through to retailers directly. Further information about this process can be found in Powerco's electricity pricing schedule (which is available at: http://www.powerco.co.nz/Publications-and-Disclosures/Pricing-Schedules/Electricity).

SHARING VALUE OF DEFERRAL OF INVESTMENT

98. Powerco recognises that the ability to control and shift load during peak times via load signalling equipment has the potential to defer investment.

99. Because of this potential to defer investment Powerco continues to offer a number of tariff options such as AICO and CTRL in the Valley and Tauranga distribution networks that provide discounts to consumers based on the availability and degree of load control at the consumer's ICP.

100. Powerco also provides a number of discounted "NITE" tariff options within these networks which are designed to incentivise consumers to shift load from peak to off-peak periods in order to flatten peaks and consequently reduce the need for new

investment. A detailed description of these tariffs and associated eligibility criteria is available on Powerco's website[15].

101. Powerco continues to encourage embedded and distributed generation by providing payments to generators equivalent to Powerco's avoided costs of transmission (subject to Powerco's Distributed Generation (DG) Policy).

13. WESTERN REGION PRICING METHODOLOGY

CONSUMER GROUPS

RATIONALE FOR CONSUMER GROUPS

102. Powerco uses three consumer groups for cost allocation and charging purposes in the Western Region. The three groups are:

- E1, which applies to all connections with a connected capacity of less than 100 kVA connections (which includes unmetered connections);
- E100, which applies to all connections with a connected capacity of between 100 and 300 kVA;
- E300, which applies to all connections with a connected capacity of greater than 300kVA (which includes connections with individually assessed pricing).

103. These price categories are based around groups of consumers with similar characteristics relating to their installed capacity and associated demand as these groups place different demands on different components of our network such as sub-transmission, high voltage (11kV) and low voltage (400V) network assets as well as onsite assets such as transformers and associated switchgear. Annex A provides information on the characteristics of the network and consumers in the Western Region.

104. The characteristics of each consumer group are provided in Table 10. Ideally, Powerco would have more information on anytime maximum demand and on peak demand but currently this information is only readily available for connections with half hourly metering. Where this information is not available assumptions have been made about the load profiles of the relevant consumers as is the case for the E1 price category where the demands are determined by subtraction.

105. The E1 price category is for all connections with a connected capacity of less than 100 kVA which represents all residential and the majority of commercial consumers. The E1 price category has been limited to less than 100 kVA to provide a relatively simple price structure for the vast majority of consumers while excluding all connections which require dedicated on-site and/or upstream assets.

106. The E100 price category is for all connections with a connected capacity of between 100 and 300 kVA, which equates to medium-large commercial consumers. This price category has been defined because connections with this level of capacity place different levels of demand on different components of our network assets such as sub-

[15] For further details on our prices and how we apply our charges please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

transmission, high voltage (11kV) and low voltage (400V) assets and typically require dedicated on-site assets such as transformers and associated switchgear.

107. The E300 price category is for all connections with a connected capacity of greater than 300 kVA which equates to large commercial / industrial consumers. This price category has been defined because connections with this level of capacity place different levels of demand on different components of our network assets such as sub-transmission, high voltage (11kV) and low voltage (400V) assets and typically require a higher level of dedicated on-site and up-stream assets (such as transformers, switchgear and feeders) than the E100 price category.

108. The specification of separate price categories for the E100 and E300 groups makes the underlying costs of supplying these consumers more transparent.

109. In addition to these price categories Powerco also has non-standard charges which apply in cases where our standard charges are not appropriate. These consumers are placed on the SPECIAL price category. This is typically only for connections with capacity greater than 1,500 kVA where there is significant network investment required for the connection and/or unique commercial arrangements that require special consideration. This is discussed in further detail in paragraphs 139 – 142.

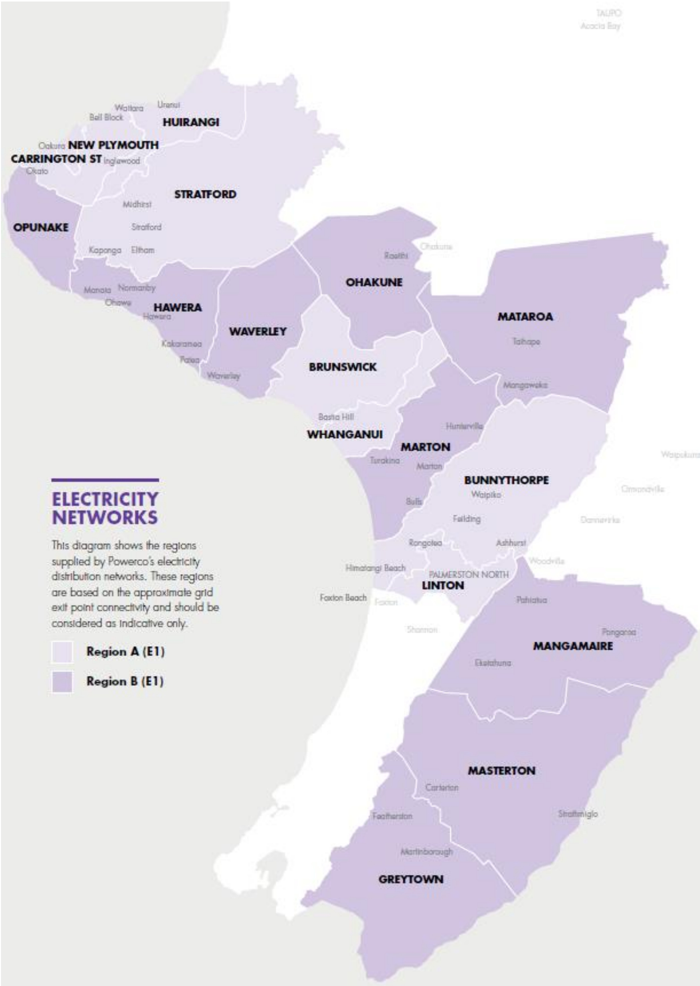
RATIONALE FOR PRICING ZONES

110. Within each price category the individual charges are classified by a pricing zone which is a grouping of GXPs with similar characteristics such as rural/urban connection density and geographical location.

111. Pricing zones allow our tariff structure to have the ability to reflect the difference in the costs of supplying consumers within specific regions across the Western network. This allows us the ability to reflect a fairer allocation of the operating costs, transmission charges and capital costs within each geographical location rather than across the entire network.

112. The E1 price category is split into two zones with Zone A being for all consumers supplied in the high density urban centres of New Plymouth, Whanganui and Palmerston North and Zone B for all consumers supplied in the remaining low density and typically rural areas (as shown in Figure 8). These two zones have been defined to be based on the similar underlying cost structures across the GXPs within each zone while keeping the tariff structure relatively simple for consumers and retailers.

Figure 8: Map of Western Electricity Network



113. The E100 and E300 price categories are split into ten zones with each zone representing a grouping of GXPs based on geographical proximity. For example, in diagram 4 the GXPs of Huirangi, Carrington St, New Plymouth, and Stratford are grouped together into zone A. The number of zones represents Powerco's preference for greater transparency of costs within this price category due to the impact that changes to individual consumer behaviour within these groups can have on the underlying cost structure.

114. The consumer groups and price zones used allow the specific underlying costs of supplying each consumer group and price zone to be more accurately reflected in our charges. these groupings represent a trade-off between the simplicity required to reduce processing costs and the level of complexity required to allocate costs while providing efficiency-promoting price signals to the relevant network users. Powerco regularly consults with customers to ensure that an appropriate balance is reached.

METHOD FOR DETERMINING THE ALLOCATION OF CONSUMERS TO GROUPS

115. Consumers are allocated to a region and pricing zone based on the GXP that is associated with their connection (as shown in Figure 7).

116. Consumers are then allocated to a price category based on the installed capacity at their connection.

117. Once allocated, price categories are published for every connection on the Electricity Registry[16] to enable retailers and other parties to determine the distribution charges that apply for that connection.

Table 9: Statistics for Western Region Consumer Groups used in the Pricing Methodology

Consumer Group	ICPs	Volume (MWh)	Anytime Maximum Demand (kW)	On Peak Demand (kW)
E1: Less than 100kVA connections	169,378	1,572,309		
E100: 100 to 300kVA connections	222	97,422	28,308	13,642
E300: Greater than 300kVA connections (including non-standard consumers)	269	719,033	178,849	84,554

COST ALLOCATION METHODOLOGY AND RATIONALE FOR ALLOCATION TO EACH CONSUMER GROUP

118. In the Western Region, Powerco uses a GXP-based pricing methodology. Prices from the previous pricing year are adjusted to reflect changes in the overall revenue requirement. The revenue stream of the updated prices is then compared to the results of the COSM. If changes in prices are required as a result of the comparison, adjustments are done while having regard to price stability.

119. For the E1 price category, prices for zone B are typically higher than zone A due to the lower connection density and greater average system length for the GXPs in zone B compared to zone A. This is reflected in the COSM outputs, which show that it is more costly (on average) to supply ICPs in the B zone. Similarly, the charges set for the price zones for the E100 and E300 groups broadly reflect the costs of supplying customers in these groups serviced from these GXPs, as shown by the COSM outputs.

120. Tables 10 and 11 provide a summary of the statistics and allocation factors used in the cost of supply model to allocated costs between regions and price categories for the Eastern Region.

[16] https://www.electricityregistry.co.nz

Table 10: Summary of the statistics used to allocate the costs of in relation to Powerco's lines business activities by key revenue components to each consumer group for the relevant financial year

WESTERN REGION						
Consumer Group	**Price Zone**	**ICPs**	**RCPDs (kW)**	**LV Asset Value ($000)**	**HV Asset Value ($000)**	**Total Asset Value ($000)**
E1 – less than 100 kVA	A	117,264	200,418	135,871	261,511	397,382
	B	52,114	84,908	61,361	220,037	281,398
E100 (100 – 300 kVA)	A	54	2,959		4,475	4,475
	B	9	551		898	898
	C	0	0		0	0
	D	1	15		58	58
	E	19	1,230		1,388	1,388
	F	5	408		862	862
	G	4	343		1,624	1,624
	H	28	1,928		4,173	4,173
	I	100	6,110		7,223	7,223
	J	2	98		403	403
E300 (300 kVA+ incl non-standard consumers)	A	84	26,940		38,485	38,485
	B	12	7,533		12,282	12,282
	C	2	1,116		3,301	3,301
	D	3	943		3,624	3,624
	E	35	9,683		10,259	10,259
	F	11	2,857		6,039	6,039
	G	3	1,024		4,847	4,847
	H	27	7,105		13,709	13,709
	I	88	25,018		28,799	28,799
	J	4	2,335		9,603	9,603
Total		**169,869**	**383,523**	**197,232**	**633,599**	**830,831**

Table 11: Summary of the factors used to allocate the costs of in relation to Powerco's lines business activities by key revenue components to each consumer group for the relevant financial year

WESTERN REGION				
Consumer Group	Price Zone	Allocator for:		
		Operating Costs	Transmission Costs	Cost of Capital
E1 – less than 100 kVA	A	49.9%	49.3%	47.8%
	B	30.6%	24.0%	33.9%
E100 (100 – 300 kVA)	A	0.8%	0.9%	0.5%
	B	0.1%	0.1%	0.1%
	C	0.0%	0.0%	0.0%
	D	0.0%	0.0%	0.0%
	E	0.2%	0.4%	0.2%
	F	0.1%	0.1%	0.1%
	G	0.2%	0.1%	0.2%
	H	0.6%	0.6%	0.5%
	I	1.0%	1.5%	0.9%
	J	0.0%	0.0%	0.0%
E300 (300 kVA+ Including non-standard consumers)	A	5.0%	6.7%	4.6%
	B	1.2%	1.8%	1.5%
	C	0.3%	0.4%	0.4%
	D	0.4%	0.5%	0.4%
	E	1.5%	2.7%	1.2%
	F	0.6%	1.0%	0.7%
	G	0.5%	0.4%	0.6%
	H	2.1%	2.4%	1.7%
	I	3.9%	6.2%	3.5%
	J	1.0%	0.9%	1.2%

QUANTIFICATION OF KEY COMPONENTS OF COSTS AND REVENUES

121. The key components of costs and revenues are described in paragraphs 36 - 45. The breakdown of these costs into consumer groups is provided in Table 12.

Table 12: Powerco's allocated revenue requirement for the 2017/18 financial year by consumer group

WESTERN REGION						
			Revenue required for:			
Consumer Group	Price Zone	ICPs	Operating Costs $(000s)	Transmission Costs $(000s)	Cost of Capital $(000s)	Total $(000s)
E1 – less than 100 kVA	A	117,264	38,549	30,116	32,446	**101,110**
	B	52,114	23,661	14,668	22,976	**61,305**
E100 (100 – 300 kVA)	A	54	599	569	365	**1,533**
	B	9	70	79	73	**222**
	C	0	0	0	0	**0**
	D	1	5	14	5	**23**
	E	19	183	222	113	**519**
	F	5	70	80	70	**220**
	G	4	128	85	133	**346**
	H	28	446	394	341	**1,180**
	I	100	805	911	590	**2,306**
	J	2	31	21	33	**85**
E300 (300 kVA+)	A	83	3,691	3,662	2,976	**10,329**
	B	10	756	449	833	**2,038**
	C	2	242	226	270	**738**
	D	3	285	306	296	**887**
	E	34	1,063	1,509	749	**3,322**
	F	11	490	595	493	**1,579**
	G	3	383	216	396	**995**
	H	21	1,165	914	853	**2,932**
	I	87	2,786	3,804	2,351	**8,941**
	J	4	745	541	784	**2,070**
Non-standard		11	1,164	1,723	690	**3,577**
Total		**169,869**	**77,317**	**61,103**	**67,836**	**206,256**

FIXED AND VARIABLE CHARGES

122. Similar to the Eastern Region, distribution costs tend to be fixed in nature rather than related to the delivered energy volumes. The assets employed are expensive and the cost of the assets is not directly related to the usage of the asset, i.e. the cost is the same regardless of whether or not the assets are being used by an end-consumer at any particular time.

123. Powerco wants to promote efficient use of the network and therefore Powerco's charges, to the extent practicable, are designed to allow end-consumers the opportunity to modify their behaviour in order to use the network efficiently.

124. In Powerco’s Western region consumers are typically charged a tariff which consists of a variable tariff (cents/kWh) and/or a demand tariff ($/kVA or $/kW) and a fixed charge (either $/day or $/kVA per day).

125. From an economic point of view, these tariffs should ideally be structured such that all marginal costs are charged on a variable basis and all other costs on a fixed basis (so as not to distort behaviour). As marginal costs are typically small (zero if spare capacity exists) this would result in the majority of charges being fixed.

126. However, a fixed charge would not reflect the impact of additional usage on future investment costs (i.e. the long run marginal cost) and hence would not provide consumers with the right incentives to control consumption during peak demand periods.

127. In the E1 price category Powerco has three types of charges which apply to all consumers in this price category. A variable volume charge (c/kwh) with different rates for consumption during the Day and Night periods, a variable demand charge for the single anytime maximum demand for the month ($/kW) and a fixed charge ($/day).

128. The E100 and E300 price categories typically have three charges:

- a distribution and transmission demand charge ($/kW/day) based on the customer’s anytime maximum demand (AMD) and their on peak demand (OPD) over the prior year, and

- a fixed charge (either $/day for the E100 group or $/kVA based on installed capacity per day).

129. The demand charges across all three price categories were initially set to reflect the costs that Powerco incurs as a result of consumers using its network during peak times. The variable and fixed charges are set at a level sufficient to recover the balance of revenue across the price categories.

130. Consumers in the E100 and E300 price categories are typically very large commercial/industrial consumers which require dedicated on-site and upstream assets (such as dedicated feeders and transformers) to meet their supply requirements. Therefore, the fixed charge component of these price categories is typically higher than the other price categories to ensure that an appropriate return on investment is earned by Powerco.

131. Powerco’s ability to amend the existing fixed and variable rate structure is somewhat restricted by the limitations imposed on residential fixed charges by the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004, the constraint imposed on total revenue by the Electricity Distribution Services Default Price-Quality Path Determination 2015 and Powerco’s own policy of avoiding price shocks to end-consumers. Consequently, Powerco determines the proportion of fixed and variable charges by reference to existing rates while recognising the largely fixed nature of the underlying costs. The regulations have a large influence on the level of the fixed and variable components for residential groups.

Table 13: Powerco's target revenue requirement split by fixed and variable charge components for each consumer group for the relevant financial year

WESTERN REGION					
Consumer Group	Price Zone	ICPs	Target Revenue Split		
			Fixed	Demand[17]	Variable
E1 – less than 100 kVA	A	117,264	3.2%	47.2%	49.6%
	B	52,114	2.3%	42.4%	55.2%
E100 (100 – 300 kVA)	A	54	11.8%	88.2%	0.0%
	B	9	7.0%	93.0%	0.0%
	C	0			
	D	1	7.8%	92.2%	0.0%
	E	19	11.3%	88.7%	0.0%
	F	5	9.2%	90.8%	0.0%
	G	4	5.7%	94.3%	0.0%
	H	28	7.7%	92.3%	0.0%
	I	100	11.6%	88.4%	0.0%
	J	2	9.2%	90.8%	0.0%
E300 (300 kVA+)	A	83	21.8%	78.2%	0.0%
	B	10	16.5%	83.5%	0.0%
	C	2	9.9%	90.1%	0.0%
	D	3	11.5%	88.5%	0.0%
	E	34	26.1%	73.9%	0.0%
	F	11	21.3%	78.7%	0.0%
	G	3	13.4%	86.6%	0.0%
	H	21	14.8%	85.2%	0.0%
	I	87	20.7%	79.3%	0.0%
	J	4	17.4%	82.6%	0.0%
Non-standard		11	98.7%	1.3%	0.0%
Total		**169,869**			

TREATMENT OF RENTAL REBATES

132. Transpower's rental rebates associated with operation of its HVAC network are excluded from the bundled tariffs and are passed through to retailers directly. Further information about this process can be found in Powerco's electricity pricing schedule (which is available at: http://www.powerco.co.nz/Publications-and-Disclosures/Pricing-Schedules/Electricity/).

SHARING VALUE OF DEFERRAL OF INVESTMENT

133. Powerco recognises that the ability to control and shift load during peak times via load signalling equipment has the potential to defer investment.

17 Including power factor charges (where applicable).

134. Because of the benefits relating to the potential to defer investment Powerco continues to offer a discount to the daily fixed charge for consumers with controllable load in the E1 consumer group of 15 cents per day (compared to the maximum low volume rate of 15 cents per day for consumers without controllable load).

135. Powerco's volume charges to the mass market group (E1) in the Western region are also structured to encourage consumers to shift load to off-peak periods by offering a significant discount of 4.5-6.5 cents/kWh for consumption during the off-peak night period (11p.m. – 7a.m.). A detailed description of the Western Region price structures and associated eligibility criteria is available on Powerco's website[18].

136. Powerco also continues to encourage embedded and distributed generation by providing payments to generators equivalent to Powerco's avoided costs of transmission (subject to Powerco's Distributed Generation (DG) Policy).

14. REVENUE SUMMARY

137. The tables below summarise the projected revenue from Powerco charges for the Eastern and Western regions for each consumer group and provide a comparison with the previous year.

Table 14: Changes to Powerco's forecasted revenue – Eastern Region

EASTERN REGION				
Distribution network	Consumer Group	Forecasted Revenue ($'000s)		
		2016/17	2017/18	Change
Tauranga	Mass market (Including Unmetered ICPs)	65,078	67,533	+2,455
	69 – 299 kVA	9,559	8,458	-1,101
	300 kVA + (including individually price consumers)	14,404	16,741	+2,337
	Total	**89,041**	**92,732**	**+3,691**
Valley	Mass market (including unmetered ICPs)	63,004	63,238	+234
	69 – 299 kVA	6,066	6,512	+446
	300 kVA + (including individually priced consumers)	19,360	22,982	+3,622
	Total	**88,430**	**92,733**	**+4,303**

[18] For further details on our prices and how we apply our charges please see the full pricing policy at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

Table 15: Changes to Powerco's forecasted revenue – Western Region

WESTERN REGION			
Consumer Group	Forecasted Revenue ($'000s):		
	2015/16	2017/18	Change
E1 – less than 100 kVA	159,540	161,343	+1,803
E100 (100 – 300 kVA)	7,620	7,558	-62
E300 (300 kVA+)	33,490	35,773	+2,283
Total	**200,650**	**204,674**	**+4,024**

138. The changes in revenue from 2016/17 to 2017/18 year are due to:
a) changes to the underlying charges that have resulted from the application of a CPI adjustment equivalent to an average price change of 0.3% (as per the DPP Determination, set by the Commerce Commission, which regulates the allowable revenue of non-exempt electricity distributors (including Powerco));
b) pass through of an increase in transmission charges and other pass through costs such as council rates and Electricity Authority and Commerce Commission levies which adds a further 1.4% to the overall price increase;
c) adjustments to Powerco's forecasts of chargeable quantities to reflect historical regional trends, including the number of ICPs and associated volume and demand growth;
d) re-balancing of our charges across regions and consumer groups to ensure that our charges better align with our underlying costs. This helps to ensure that all consumers across our various regions and consumer groups pay a fair and equitable amount which reflects their utilisation of our network and the costs associated with their supply;
e) the migration of consumers between consumer groups such as the migration of approximately 100 customers from the 69-299 kVA price categories to the mass market price categories. This migration of customers results in a lower revenue forecast for the 69-299 kVA consumer group and a higher revenue forecast for the lower mass market forecast (as detailed in table 14);
f) adjustments to individual asset based pricing to reflect revised demands and asset allocations for customers that are in the 300 kVA consumer groups.

15. APPROACH TO SETTING PRICES FOR NON-STANDARD CONTRACTS

EXTENT OF NON-STANDARD CONTRACT USE

NUMBER OF ICPS REPRESENTED BY NON-STANDARD CONTRACTS AND THE VALUE OF TARGET REVENUE EXPECTED TO BE COLLECTED FROM CONSUMERS SUBJECT TO NON-STANDARD CONTRACTS

139. The number, size and pricing characteristics of non-standard customers on Powerco's network are described in tables 7 and 8 and paragraphs 55 – 65.

HOW POWERCO DETERMINES WHETHER TO USE A NON-STANDARD CONTRACT, INCLUDING ANY CRITERIA USED

140. Powerco's practice is to offer non-standard pricing and individual account management to industrial and large commercial customers to address the risk of uneconomic bypass and to enable arrangements that are tailored to customers' needs. Customers must first discuss the prospect of bypass directly with their individual account managers before non-standard pricing for this reason will be considered. Powerco's approach to non-standard pricing includes taking into account customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

141. Through these processes, Powerco discourages uneconomic bypass of its network and promotes direct negotiation to tailor its services to the specific needs of the business. For example, a number of years ago Powerco determined that a large industrial consumer group in the Wairarapa region presented a potential bypass threat due to its size and location. Powerco subsequently reached agreed commercial terms with this consumer group to mitigate the risk of uneconomic bypass. Further details on non-standard pricing is available on Powerco's website at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

142. This approach is consistent with pricing principle (c)(i).

POWERCO'S OBLIGATIONS AND RESPONSIBILITIES TO CONSUMERS SUBJECT TO NON-STANDARD CONTRACTS IN THE EVENT THAT THE SUPPLY OF ELECTRICITY LINES SERVICES IS INTERRUPTED

143. Non-standard contracted consumers are generally significant commercial or industrial loads, and thus arrangements between the parties include provision for response to planned and unplanned interruptions. For example, such customers are given direct contact with Powerco's Network Operations Centre which enables them to liaise directly should a network event occur and help co-ordinate restoration. Some non-standard agreements include operational protocols detailing the management of load in the event of maximum demand levels being reached, or management in the event of abnormal network configurations.

144. These arrangements have no direct effect on the determination of prices for these consumers.

POWERCO'S APPROACH TO DEVELOPING PRICES FOR ELECTRICITY DISTRIBUTION SERVICES PROVIDED TO CONSUMERS THAT OWN DISTRIBUTED GENERATION

145. Powerco currently does not impose any standard ongoing charges in relation to distributed generation, but we do apply connection charges for the connection of distributed generation. These charges are negotiated directly with the customer and are consistent with the pricing principles in Schedule 6.4 to Part 6 of the Electricity Industry Participation Code 2010.

146. The connection charges are based on the incremental costs of providing connection services to the distributed generation, assuming recovery of the reasonable costs incurred by Powerco to connect the generator and to comply with Powerco's connection and operation standards. The incremental cost is net of the transmission

and distribution costs that an efficient service provider would be able to avoid as a result of the connection of the distributed generation.

147. Where the incremental costs are negative the generator is deemed to be providing “network support services” (also referred to as “avoided cost of transmission” (ACOT)) and may invoice Powerco for this service providing the generator can provide evidence to Powerco that the generator is, in fact, providing “network support services” to Powerco’s network as described above, and complies with all relevant legal obligations (including tax obligations).

148. ACOT is determined in the following way:

- The annual interconnection charge[19] that Powerco pays to Transpower is determined based on Powerco’s offtake at the GXP coincident with the regional peak demand periods occurring during the capacity measurement period for the applicable Pricing Year.

- ACOT will be calculated using the Transpower Interconnection Rate applicable to the pricing year.

- The annual ACOT amount will be the difference between:

  a) the average of the regional coincident peak demand at the GXP (as notified by Transpower); and

  b) the average of Powerco’s net offtake (in kW), as measured at the GXP, plus the net electricity (in kW) injected into Powerco’s network by the generation station at the generator’s grid connection point for each regional peak demand period.

149. Any payment due to the customer in respect of the ACOT payment may be netted off by Powerco against any network charges due and payable by the generator to Powerco.

150. Further information on Powerco’s distributed generation policy is available at: www.powerco.co.nz/Get-Connected/Distributed-Generation/

[19] All terms are as defined in the transmission pricing methodology set out in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010.

Table 16: Value of forecasted ACOT payments for 2017/18 financial year by GXP

Generator	GXP	RCPD (kW)	ACOT ($/year)
Generator 1	Bunnythorpe	6,921	$858,038
Generator 2	Carrington	4,412	$547,057
Generator 3	Greytown	1,507	$186,868
Generator 4	Hawera	22,549	$1,730,729
Generator 6	Huirangi	3,636	$450,816
Generator 7	Huirangi	1,129	$140,016
Generator 8	Linton	8,551	$1,060,180
Generator 9	Linton	53	$6,568
Generator 10	Masterton	400	$49,585
Generator 11	Ohakune	224	$27,769
Generator 12	Opunake	268	$33,187
Generator 13	Stratford	5,141	$637,403
Generator 14	Stratford	466	$57,802
Generator 15	Stratford	334	$41,444
Generator 16	Tauranga	36,406	$4,513,641
Generator 17	Waikino	584	$72,384
Total – Yearly		**92,583**	**$10,413,487**

16. COMPLIANCE WITH ELECTRICITY AUTHORITY'S PRICING PRINCIPLES

151. This section demonstrates how Powerco's pricing methodology complies with the Electricity Authority's pricing principles.

152. The pricing principles are based on sound economic theory, but it can be difficult to demonstrate compliance using quantitative information. Powerco considers that it is currently compliant with the pricing principles. However, we will continue to gather and analyse more information on consumers' behaviour and assess that information against the principles.

153. Particular matters we will continue to investigate and monitor over the medium-term are:

- the impact a stronger peak demand pricing signal would have on different types of consumers' electricity usage;
- the benefits and consequences of greater alignment of the pricing approaches used in the Eastern and Western regions; and
- the willingness of consumers to accept price adjustments.

a) i) Prices are to signal the economic costs of service provision, by 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 regulation.

INCREMENTAL COST

154. The term "incremental cost" (IC) is defined as the cost of the next additional unit of production and "long run incremental cost" (LRIC) is defined as the cost of providing an additional unit, including the capital cost of increasing the capacity of the network. The LRIC may be the present value of the cost of a future addition to the network.

155. Incremental costs are difficult to evaluate in a meaningful way for electricity distribution businesses (EDBs). Much of the time the IC is zero, meaning that the next unit of electricity can be distributed to a customer within the existing capacity of the network system. Once in a while the IC will be a very large number, meaning that the next unit of electricity would require additional installed capacity to be distributed.

156. In addition, the "unit" being supplied could be an extra unit of capacity to an existing customer, or providing a connection for a new customer. To calculate IC, Powerco has analysed the forecasted level of growth on the network over the next ten years against the forecasted customer connection and system growth capex. This results in a proxy for incremental cost of 0.98 c/kWh.

157. Powerco is required by legislation to supply some consumers at prices which may be below the marginal cost of connection. This is mainly in remote locations which have few customers and where electricity supply was originally supported by public subsidisation. In some cases the cost of renewing these assets is greater than the present value of the line charges that would be recovered over the lives of the assets. The Electricity Industry Act 2010 now allows EDBs to provide alternative energy supply, rather than continuance of supply via line services. Powerco is actively identifying these customers and has installed several standalone power systems. With consumer consent, we will seek to install additional standalone systems where this is appropriate.

STANDALONE COST

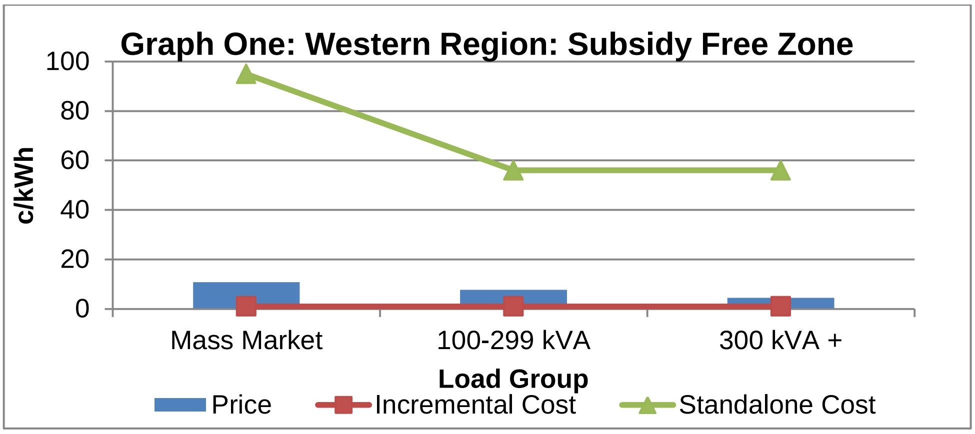
158. Cross subsidisation exists when customers pay more for a service than the costs another firm would incur if it served those customers on a stand-alone basis. Standalone cost (SAC) is also a difficult figure to calculate for each load group on Powerco's network. Powerco has attempted to calculate the SAC for each tariff group by considering the costs of alternative power supply. A Ministry of Economic Development Report provided c/kWh estimates for stand-alone photo-voltaic power systems for different levels of capacity. We have used the estimated costs for the Auckland region for the '<2kW' group (mass market) of \$0.95/kWh and the '>100 kW' group (100 kVA -199 kVA & 300 kVA +) of \$0.56 /kWh as an estimate of stand-alone costs across the network.[20]

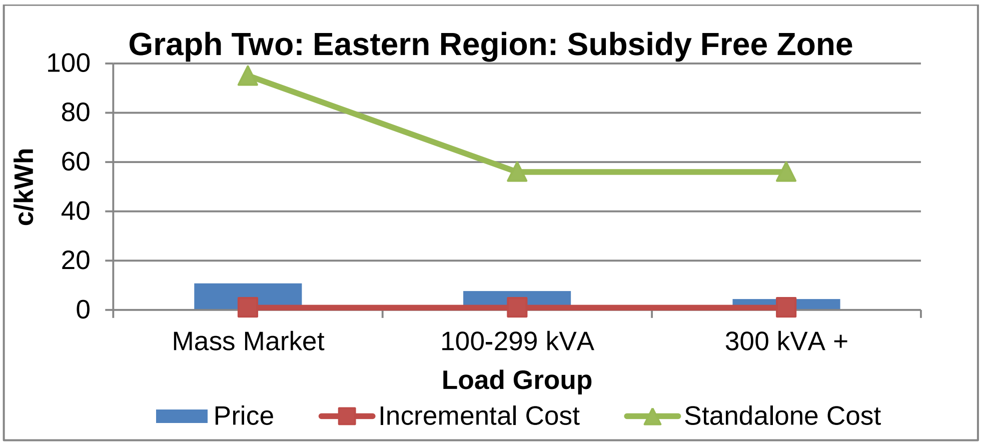
SUBSIDY FREE ZONE

[20] See http://www.med.govt.nz/sectors-industries/energy/energy-modelling/technical-papers/solar-photovoltaic-energy

159. Graphs One and Two in Figure 9 below indicate that Powerco's pricing is within the subsidy-free zone for each of Powerco's tariff group.

Figure 9: Illustration of how Powerco's prices fall within the subsidy-free zone





160. A large number of assumptions have been made when determining the IC and SAC estimates, and, as only part of Powerco's pricing is by volume, the graphs should be considered illustrative only. We also recognise that the simplified approach does not recognise locational factors (other than between the Eastern and Western regions). For example, the averaging could mask the difference between rural and urban consumers and obscure the few specific customers that are supplied at below marginal cost.

161. However, Powerco's use of a cost of supply model provides additional reassurance that prices are in the subsidy free zone by allocating actual costs of supply to individual price categories. By regularly reviewing the costs of supply and revenue by price category Powerco ensures that our charges fall within the subsidy free zone.

a) ii) Prices are to signal the economic costs of service provision, by having regard, to the extent practicable, to the level of available service capacity.

a) iii) Prices are to signal the economic costs of service provision, by signalling, to the extent practicable, the impact of additional usage on future investment costs.

162. These two principles essentially reflect opposite sides of the same coin, both requiring that prices should look to the future and be based on long run marginal costs. In essence, prices should be low where future investment is low (and spare capacity exists,; and prices should be high where capacity is constrained and investment is needed.

163. The most significant cost driver that influences the need to invest to develop the network is the combined peak demand of all consumers in an area. Powerco designs and constructs its network to meet this peak load.

164. Powerco's tariffs in the Eastern and Western regions are structured to reflect different capacity bands, which allow us to differentiate our charges based on the provision of different levels of end-use capacity to our consumers.

165. Our tariffs across both regions also provide differentials between peak and off-peak consumption in order to reflect the difference in long term costs associated with investment in additional network capacity.

166. Powerco's demand charge in the Western region for both mass market and larger commercial/industrial customers is designed to signal the cost of new investment by ensuring that consumers that contribute towards the peak demand on our network are charged accordingly.

167. In addition, Powerco offers discounted charges for customers who opt for load control tariffs. Configured well, load control systems are highly effective at reducing demands at peak times by deferring non-time-critical power usage. The benefits of load-control systems include more predictable peak demand magnitudes, fewer peaking generation plants and deferred transmission and distribution capacity augmentations. The benefits accrue across the entire electricity sector.

168. Transmission costs are a function of transmission capacity and signal the economic costs of service provision on the Transpower network. These costs represent around 25% of distribution prices, so also work to ensure distribution prices meet this principle.

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.

169. Given the nature of distribution networks, prices based on efficient incremental costs are likely to under-recover allowed revenues. However, setting prices based on a precise definition of price responsiveness, or price elasticity of demand, is difficult for electricity distribution for a number of reasons. First, there is limited information on the actual price elasticity of demand for electricity in New Zealand. Second, retailers re-bundle distribution prices into a final retail price for their consumers. In many cases, the structure of distributors' prices (i.e. the extent to which prices are charged on a daily or per unit of energy basis) is changed by retailers. It is therefore very difficult to discern customers' responsiveness to changes in distribution prices alone.

170. The Commerce Commission, in its work on the pricing methodologies of regulated suppliers, has acknowledged the difficulty of this issue. It has stated that it would judge this principle by checking to see if certain rules have been followed. For example, where one group of consumers is less price-responsive than another group

of consumers of the same service, then, all else being equal, one would expect the prices of the less price-responsive consumers to be higher.

171. Graphs one and two in Figure 8 show that, as consumers' capacity increases, the unit cost expressed as a c/kWh charge reduces. Larger consumers tend to exhibit a higher price elasticity of demand, because they are typically better able to modify their usage patterns to consume during low cost periods or switch to alternative energy sources (e.g. gas) if the cost of electricity rises. As larger consumers also face, on average, lower prices per unit, this is consistent with the Commerce Commission's expectation.[21]

c) i) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to discourage uneconomic bypass.

172. The main risk of bypass of the distribution network is large consumers opting to connect directly to the Transpower's network or install generation. Powerco's practice is to offer non-standard pricing and individual account management to industrial and large commercial customers to address the risk of uneconomic bypass and to enable arrangements that are tailored to customers' needs. Powerco's approach to non-standard pricing includes taking into account customers' individual capacity and demand to ensure, to the extent practicable, that the price is cost reflective.

173. Therefore when Powerco becomes aware of the potential for bypass it is through these processes that we discourage uneconomic bypass of our network by promoting direct negotiation to tailor our services to the specific needs of the business. For example, a number of years ago Powerco determined that a large industrial consumer group in the Wairarapa region presented a potential by-pass threat due to its size and location. Powerco subsequently agreed commercial terms with this consumer group to mitigate the risk of uneconomic by-pass. Further details on non-standard pricing is available on Powerco's website at: http://www.powerco.co.nz/Publications/Disclosures/Electricity/

c) ii) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to 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.

174. Mass market customers are generally not able to choose the quality of service they receive. For example, Powerco cannot offer one person a higher quality and higher price than their neighbour. Powerco has an extensive consultation programme to help it understand the general preferences of consumers and this is reflected in our asset management planning process. Details of this consultation programme are available in Powerco's 2009-2011 Consultation Report, available on Powerco's website. This report describes Powerco's approach to consultation in more detail and summarises key messages from consumers.

175. Feedback suggests Powerco's networks provide an appropriate level of quality. For example, in the last 24 months Powerco surveyed 2,189 customers on its networks.

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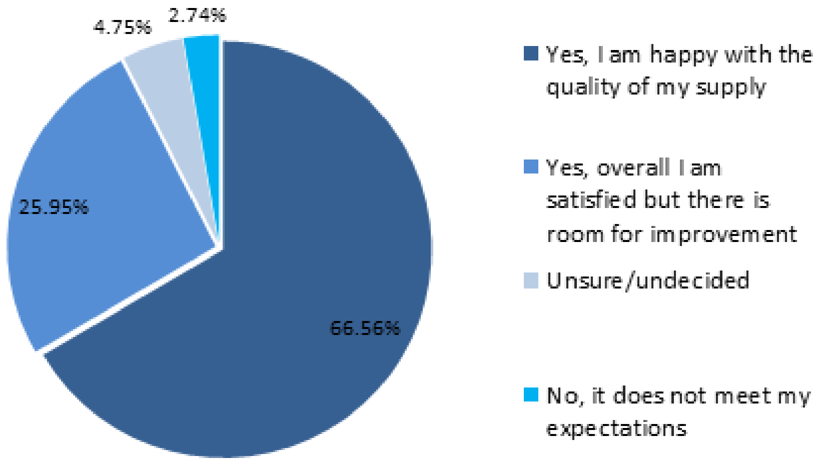
[21] Research on how elasticity of electricity consumers based on size is very limited. However, in Powerco's experience large electricity consumers demonstrate a stronger interest in price signals to shift load. See Powerco's Consumer Report 2009-2011 for a summary of the feedback from consumers.

Only 2.74% said the current quality of their electricity supply did not meet their expectations. The results are shown in Figure 10 below.

Figure 10: Responses to Powerco's customer satisfaction survey



Powerco's stakeholders and how their interests are identified are described below.

STAKEHOLDER	MAIN INTEREST	HOW STAKEHOLDERS' INTERESTS ARE IDENTIFIED
Electricity consumers	• Service quality and reliability • Price • Safety • Information • Environmental	• Consultation and retailer feedback • Dedicated client managers for large consumers • Appropriate price paths and quality standards • Incident reports, complaints and complements • Measurement and benchmarking of Powerco performance
Retailers	• Efficient business-to-business processes • Service to final consumers • Price	• Dedicated relationship client managers • Contracting agreements • Direct engagement
Embedded Generators	• Technical performance and rules • Reliability • Connection agreement	• Direct engagement and negotiation • Contractual connection agreements
Transpower (as grid and system operator)	• Technical performance and rules compliance • GXP loading and planning	• Direct engagement • Administration of Electricity Governance Rules
Commerce Commission	• Pricing levels • Quality standards • Effective governance	• Meetings with Commissioners and staff • Quality responses to consultation papers, decision papers and regulatory determinations
State bodies and regulators	• Safety via the Ministry of Economic Development • Market operation and access via the Electricity Authority • Environmental performance via the Ministry for the Environment	• Published acts, rules and determinations • Formal reporting • On-going consultation
Powerco's shareholders	• Efficient and effective business management and planning • Financial performance • Governance • Risk management	• Corporate governance and arrangements • Formal reporting • KPIs
Employees and Contractors	• Safe, productive working environment • Training and development • Continuous improvement, adoption of new technology and practices	• Regular dialogue, internal communications and employee surveys • Contractor negotiations and dialogue • Unions and employee arrangements
Public, iwi, landowners	• Public safety • Land access and respect for traditional lands • Environmental	• Consultation and feedback • Access and easement negotiations and agreements • Acts, regulation and other requirements

176. At the community level, Powerco has considered the price quality trade-off associated with proposed investments. For example, Powerco undertook a consultation process with the Taihape community. The substation supplying the town and surrounding area only has one transformer. If this were to fail around 3,800 consumers would lose supply. Powerco consulted with the community on whether it would be prepared to incur higher line charges to fund installation of a second transformer. The feedback from the community was they were not willing to accept higher charges.

177. For non-standard customers, Powerco is able to offer a service more tailored to their requirements. Powerco continues to consult with these customers through one-to-one liaison with key account managers, consistent with the Parsons Brinckerhoff

Associates best practice recommendations.[22] This works well as large customers are usually familiar with the issues involved in price/quality trade-offs and strong relationships provide a firm foundation for discussing all aspects of quality and price.

178. The number, size and pricing characteristics of non-standard customers on Powerco's network are described in tables 7 and 8 and in paragraphs 55 – 65.

c) iii) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to, where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation

179. Section 7.8.2 and 8.5 of Powerco's AMP reviews distribution alternatives and technological innovation. Powerco's pricing methodology aims to complement this asset management approach. Below are some examples of how this works:

- Demand-side management is encouraged through demand-based network charges in some cases.

- Load control is used to reduce demand peaks. This has been proposed to modify the timing of irrigation pump use in areas where voltage complaints have arisen.

- Power factor correction is best applied at customers' installations and this is set out in Powerco's connection standard. In some cases it is applied to the distribution network, particularly in the Valley area, with shunt capacitors (generally 750 kVA banks) used at key locations on distribution feeders. Powerco's pricing provides an incentive to manage the power factor and recover costs.

- Load transfer through the distribution network is considered prior to any substation capacity upgrade, and the effectiveness of price signals to manage demand.

- Solar-powered installations have been supplied in place of network extensions for some remote small loads, such as electric fence units.

- Micro-grids and remote-area power systems are being implemented in some remote rural areas. As explained earlier, the recent changes in the Electricity Industry Act 2010 allow Powerco to work with consumers to install alternative energy supply. An example of this is Powerco's "**BASE**POWER" product which provides a continuous and reliable supply of electricity, similar or better than grid supply. **BASE**POWER is a modular system with a generator, energy storage and innovative energy management system combined with renewable supplies from PV solar panels, micro hydro and, potentially, wind turbines.[23] This also provides Powerco with information about changes to standalone costs.

[22] Parsons Brinckerhoff (April 2005) Report to the Commerce Commission: *Electricity Distribution Business Asset Management Plans and Consumer Engagement: Best Practice Recommendations*, section 6.4.2.2, p.56.

[23] More information on adoption rates and pricing is available from Powerco on request.

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.

TRANSPARENCY

180. Powerco's prices for 2017/17 are available to customers through a range of media channels and locations:

- two advertisements each year in the *Wairarapa Times Age*, *Manawatu Standard*, *Wanganui Chronicle*, *Taranaki Daily News*, *Bay of Plenty Times* and *Waikato Times*;
- pricing schedules are sent to all customers with whom Powerco has a use of system agreement;
- Powerco's website; and
- available to view on request or at our offices by appointment.

181. This pricing methodology is also published on Powerco's website.

PRICE STABILITY, CERTAINTY AND IMPACT ON CUSTOMERS

182. The impact on customers of changes to the established allocation methodology is a central consideration in the pricing process. This is the reason that Powerco has moved away from the pricing it inherited from UNL very cautiously.

183. Powerco's pricing methodology has not changed materially over the last five years. In particular, the level of differential between peak and off-peak charges has not changed materially, which provides retailers and consumers with a degree of certainty when making decisions about investment in energy saving and off-peak devices.

184. Powerco is, however, continually looking to improve its pricing methodology to ensure that the balance between price categories, fixed and variable charges and the peak and off-peak differentials are appropriate. Our pricing methodology must also complement technological developments, such as the roll out of advanced metering infrastructure, the fall in cost of photovoltaic technology and the uptake of plug-in electric vehicles.

185. Powerco consults with retailers and other customers a number of times throughout the year to discuss our pricing methodology (including potential improvements) and the impact of any pending review of our prices. A description of this process is available on request from Powerco.

186. For non-standard customers, Powerco continues to consult with customers through one-to-one liaison with key account managers which provides a channel for discussions around all aspects of quality and price.

e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

187. Powerco is very aware of transaction costs and seeks to minimise them where feasible. Some examples of transaction costs that exist when Powerco transacts with key groups, and how we take these into account, are:

188. **Retailers:** Transaction costs can occur when billing systems, the pricing strategy and/or risk management strategy are amended to accommodate large distribution price changes. Fourteen retailers operate on Powerco's network and we have a detailed consultation process, generally with three rounds of consultation on prices with retailers. The pricing methodology has not changed materially from last year but we will continue to rationalise our price categories and tariff options to ensure that retailers' transactions costs are minimised.

189. **Consumers:** Consumers make medium to long term investments based on electricity price structures. For example, a very low night rate may provide an incentive to invest in a storage heater. Powerco is aware that consumers value pricing certainty and aims to minimise any large changes that impact these types of investment decisions. We mainly collect feedback from retailers (as they have responsibility for the ultimate price signal), but also collect information from consumer consultation.

190. Powerco also takes the impact on the following stakeholders into account when setting prices. An overview of our relationship with these stakeholders is described in section 2.4 of Powerco's Asset Management Plan.

- Transpower;
- Commerce Commission;
- Ministry of Business, Innovation and Employment;
- Electricity Authority;
- Electricity and Gas Complaints Commission.

ECONOMIC EQUIVALENCE ACROSS RETAILERS

191. Powerco's pricing methodology is applied consistently to all retailers. All retailers in the same region face the same tariff options, applicable charges and/or calculation methodology. Therefore we consider our prices to be economically equivalent across retailers.

192. Powerco's annual consultation process with retailers also allows them to raise any concerns over pricing at an early stage of the pricing process.

17. SUMMARY OF COMPLIANCE WITH CLAUSES 2.4.1 TO 2.4.5 OF THE ELECTRICITY INFORMATION DISCLOSURE DETERMINATION 2012

Requirement	Compliance demonstrated
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	Powerco's Electricity Pricing Methodology does this.
(2) Describes any changes in prices and target revenues;	See Table 14 and Table 15 for changes to the target (or forecast) revenues and paragraph 138 for a description of the changes. Modifications to the pricing methodology are described in Section 6.
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	See Section 15.
(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	See paragraphs 174 to 177.
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	There have been no changes to the methodology.
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Powerco's Electricity Pricing Methodology does this.
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	See section 16

(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See Table 2.
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	See Table 2, Table 7 and Table 12.
(5) State the consumer groups for whom prices have been set, and describe– (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	See paragraphs 72 to 85 and paragraphs 102 to 117.
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section 6 details the updates that have been made to our pricing schedule.
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	See sections 12 and 13.
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See Table 8 and Table 13.
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Section 5 describes the pricing strategy that Powerco has adopted in principle. The strategy involves transitioning the Western Region to ICP-based pricing and introducing differential time-of-use charging to better reflect the long run marginal cost of network use during the daily peak consumption periods. The introduction of these changes is contingent on achieving a penetration of smart meters that exceeds 70% of ICPs. For the current disclosure year (and until the new strategy is adopted) the existing pricing methodology will continue to apply.
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	For this disclosure year, there is no material change for the different consumer groups. Once the new strategy is adopted, it is envisaged that prices will become more transparent, consistent, efficient and cost reflective.

(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	See the description of the pricing strategy and its rationale above.
2.4.5 Every disclosure under clause 2.4.1 above must–	
(1) Describe the approach to setting prices for non-standard contracts, including– (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	See section 15, Table 7, and Table 12.
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	See paragraphs 140, 141 and 177.
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	See paragraphs 140, 141 and 177.
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain— (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	See paragraphs 143 and 144.
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	See paragraphs 145 to 150 and Table 16.

18. CERTIFICATION OF YEAR BEGINNING DISCLOSURE

We, Michael Bessell

and John Loughlin ,

being directors of Powerco Limited certify that, having made all reasonable enquiry, to the best of our knowledge—

(a) the following attached information of Powerco Limited prepared for the purposes of clauses 2.4.1 - 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination;

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

Signed:

Director

Date: 16 / 3 / 2017

Director

Date: 16 / 3 / 2017

APPENDIX: CHARACTERISTICS OF POWERCO'S EASTERN AND WESTERN NETWORKS

AREA NETWORK DESCRIPTIONS

193. Powerco has two contiguous networks, but within these there used to be several previously separate distribution network entities. By virtue of their history, each of these network parts has its own unique characteristics that need to be taken into account in the pricing methodology.

WESTERN REGION

194. The Western region has four areas: Manawatu, Taranaki, Wairarapa and Wanganui. Due to the size of the region, consumer groups are separated by GXP to more accurately reflect costs.

195. The Manawatu region has three areas, based on the areas of the electricity supply authorities that used to operate them. These are Manawatu, Palmerston North and Tararua. The Manawatu rural sub-transmission network (ex-Manawatu Oroua EPB) consists of open 33kV rings feeding four substations around the periphery of Palmerston North and 33kV radial feeders to Sanson and Kimbolton via Feilding.

196. The Taranaki area comprises three areas, based on the areas of the electricity supply authorities that used to operate them. These are New Plymouth, Taranaki and Egmont. The New Plymouth sub-transmission network consists of two 33kV cables supplying City Substation from Carrington GXP, two 33kV lines from Carrington GXP and one 33kV line from Huirangi GXP supplying Bell Block Substation, two 33kV cables owned by Powerco linking New Plymouth Power Station (NPPS) and Moturoa GXP, and two 33kV lines from Huirangi GXP to Mamaku Rd Substation.

197. The Taranaki sub-transmission network is an interconnected network supplying 12 zone substations from Huirangi GXP and Stratford GXP. The distribution network around Inglewood operates at 6.6kV – conversion may take place to 11kV or to 22kV. Some of the towns have load control via pilot wire and this can be complicated to reinstate If It fails.

198. The Egmont sub-transmission network supplies the south Taranaki area and consists of Cambria Substation supplied via two oil-filled 33kV cables, and four zone substations supplied via two 33kV line closed rings from Hawera GXP. It also supplies three zone substations from Opunake GXP via an interconnected 33kV line network. One of these feeds the Oaonui Shore Station.

199. The Wairarapa region covers the Wairarapa area from south of Eketahuna to Cape Palliser. Masterton has significant industrial load. The Wairarapa area has predominantly dairy farming load, although there are also many orchards and vineyards. The network is supplied from Masterton GXP and Greytown GXP.

200. The Whanganui region covers the area from Waiouru in the north to Bulls in the south, and includes the Rangitikei and Whanganui areas. The Whanganui network consists of four areas, Wanganui, Marton, Taihape and Raetihi. Wanganui and Marton have significant industrial load. The rural area has a predominantly mixed farming load.

201. The Whanganui area is supplied from two Transpower GXPs at opposite sides of the city, Wanganui GXP and Brunswick GXP. A 33kV line runs between these, passing through substations at Peat St, Castlecliff, Beach Rd and Taupo Quay on the way. Hatricks Wharf Substation is connected by 33kV line to Wanganui GXP and by 33kV cable and line to Peat St. A radial line connects Peat St to Kai Iwi Substation, and another connects Brunswick GXP to Roberts Ave Substation. A radial line connects Wanganui GXP to Wanganui East Substation, and two short radial lines connect Wanganui GXP to the adjacent Blink Bonnie Substation.

TAURANGA NETWORK: EASTERN REGION

202. The Tauranga region covers the western Bay of Plenty area from near Athenree, north of Katikati to Otamarakau, east of Te Puke. Tauranga has significant industrial load and a major port. The Bay of Plenty area has predominantly dairy and orchard load, particularly kiwifruit and avocados.

203. Tauranga has two areas based on the electricity supply authorities that used to operate them. These are the ex-Tauranga Electricity Limited network supplying Tauranga CBD and the surrounding area, and the former Tauranga EPB network, which supplies the remainder. These areas used to be separately operated due to being supplied by transformers with different vector groups, but the Dy11 transformers have now been replaced with Yy0 units, and integration of the networks is proceeding.

VALLEY NETWORK: EASTERN REGION

204. The Valley region covers the eastern area of the Waikato as far south as Kinleith, plus Waihi and the Coromandel Peninsula. Several small towns have some industrial load, but the rural area has predominantly dairy farming load. The region has five grid exit points supplying Powerco's network at 66, 33 and 11kV.

205. Kopu GXP supplies six substations on the Coromandel Peninsula and the Hauraki Plains at 66kV with a mixture of ring and radial feeds. From Waikino GXP, 33kV lines run to Waihi, Whangamata, Waihi Beach and Paeroa also in a mixture of ring and radial feeds.

206. Waihou GXP supplies the Piako area. A 33kV meshed network supplies Morrinsville, Waitoa, Farmer Rd, Piako and Walton Substations, although Walton and Morrinsville are operated in radial configuration. Tahuna is supplied via a radial spur from Waihou GXP. Mikkelsen Rd, adjacent to Waihou GXP, is supplied by twin 33kV connections.

207. Hinuera GXP supplies the area around Matamata, Tirau and Putaruru. The network consists of single radial feeds to Tower Rd, Browne St and Waharoa, and Putaruru via Tirau. This network can be partially backed up via a 33kV line between Walton and Browne St.

208. Kinleith GXP supplies at 33kV and 11kV. The 33kV network supplies two substations at Tokoroa, Maraetai Rd and Baird Rd, and the two substations associated with the water pumping stations for the Kinleith mill at Midway and Lakeside.

209. Supply at 11kV is taken from Kinleith GXP for the Kinleith mill site. A co-generation plant is connected to the Kinleith GXP.

NETWORK ASSETS BY PREVAILING CUSTOMER TYPE

INDUSTRIAL AND COMMERCIAL (F1)

210. The network configuration for large industrial customers is commensurate with the nature and capacity of the customer's load. Typically, for customers with a demand above 3MVA, dual 11kV feeders are available, providing a no-break supply for maintenance, or backup in the event of a single fault. Automated or remote control of 11kV switching is provided for some major customers. The cable and conductor sizes reflect the load size. In general, newer areas have underground reticulation, while older areas are overhead.

211. Due to the higher load currents, there tends to be limited load transfer capacity through the 400V networks. Typically radial 400V feeders from the transformer to the consumer are provided. In some industrial subdivisions 400V interconnection between feeders is provided using either 240mm2 or 185mm2 aluminium cable, but load transfer is limited.

KINLEITH MILL SITE

212. There is a significant network owned and operated by Powerco supplying 33kV sub-transmission and 11kV distribution assets located at the Carter Holt Harvey Pulp Paper Mill at Kinleith, near Tokoroa. The network is highly interconnected, beginning at the cable terminations of the Transpower switchgear at the Kinleith GXP, and ending at the low-voltage terminals of the supply transformers. The system is mainly underground, comprising 29 11kV feeders, and including one 33kV circuit that supplies Midway and Lakeside substations.

TE REREHAU WINDFARM SITE

213. An underground cable reticulation system links wind turbines in the Manawatu area and connects them to the Tararua 3 transmission GIP. This comprises 28km of 33kV underground cable, presently 81 33kV/400V distribution transformers, an optical fibre network and a 33kV switching station.

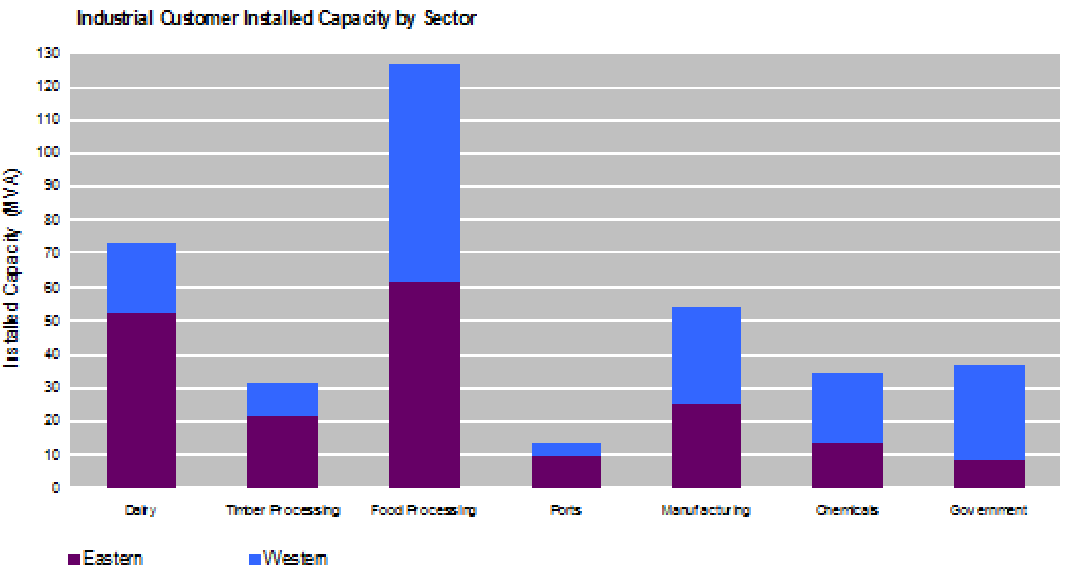
LARGE CUSTOMERS

214. Customers with an installed capacity of greater than 1.5MVA (owned by Powerco and excluding Kinleith) are characterised as follows:

Region	Number of large customers	Total installed capacity
Eastern Region	47 customers	Over 192 MVA
Western Region	52 customers	Over 190 MVA

215. The installed capacity of Powerco's major industrial customers by industry sector is illustrated in Figure 11 below.

Figure 11: Installed transformer capacity by large customer sector



Notes

1. Timber processing sector includes sawmills and wood processing plants. It excludes the Kinleith pulp and Paper mill site.

2. The food processing sector includes meat and chicken industries, flour industries, major cool stores, major bakeries and breweries.

3. The Manufacturing sector includes vehicle assembly, plastic pipeline, carpets and electrical cable industries.

4. The Chemical sector includes oil and gas process industries.

5. The Government sector includes the NZ Defence Force bases, university campus and research facilities.

6. Some customers own their own transformer capacity.

216. The size of these customers puts them on feeders with a Powerco security class of F1 or F2, which requires a security of supply of at least AA (restoration time of 45 minutes).

DAIRY SECTOR

217. The dairy industry electricity peak demands occur in spring. The industry is reliant on a reliable electricity supply, so shutdowns for maintenance or network upgrade activities have to be planned for the dairy dry season, especially in South Waikato and South Taranaki.

218. At an individual farm level, operations are intensifying and amalgamating. There is greater use of irrigation and new technologies. The overall impact is that the load is increasing and the operations require higher reliability of supply and better quality of supply than was previously the case. This is consuming existing spare capacity, creating a greater onus on effective network planning and operations.

TIMBER PROCESSING SECTOR

219. Timber processing facilities may be located in remote areas where there is low network security. This means that outage planning may involve extensive customer consultation and that voltage fluctuations may occur.

FOOD PROCESSING SECTOR

220. Outage requirements for customers in this sector can usually be co-ordinated if sufficient notice is given. Unplanned outages can lead to spoiled products, causing expensive wastage and staff disruption. Cool stores are significant growth packages and can have heavy, peaky loads. Careful planning is needed to ensure adequate backfeed capability is allowed for these loads. Backup capacities to the full site capacities are becoming more difficult to provide due to the size of the loads.

TRANSPORTATION SECTOR

221. Port operations are based around shipping movements and the quick turnaround of ships is important. When ships are in port, the facilities make heavy demands on the electricity distribution network and at these times a highly reliable supply is needed to ensure a fast turnaround. A secure supply (N-1) is therefore needed by ports. Continued drive for efficiency and increasing demands in this sector has been squeezing the windows available for maintenance. Both of the main ports supplied by Powerco are on growth paths. The port in Tauranga is highly competitive with a large expansion planned. Improvements in the capacity of the rail link between New Plymouth and Marton have occurred but the closure of the rail link from Stratford to Taumarunui could constrain Westgate’s future growth path.

MANUFACTURING SECTOR

222. The manufacturing sector is dependent on the prevailing general economic conditions and the economic conditions within the industry’s particular niche. The requirements on the electricity distribution network can therefore vary accordingly.

CHEMICALS SECTOR

223. The chemical sector is heavily reliant on a reliable supply of electricity with few voltage disturbances. Some of the machines in this industry can create large voltage dips on the network when they start. This needs ongoing co-ordination with the customers.

GOVERNMENT SECTOR AND RESEARCH FACILITIES

224. Some of the Government sector organisations have on-site generation which needs to be co-ordinated with Powerco’s network operations.

CENTRAL BUSINESS DISTRICT NETWORKS

225. The networks in the Tauranga, Palmerston North, New Plymouth, Whanganui, Tokoroa and Masterton central business districts (CBDs) consist of highly interconnectable 11kV radial feeders. Switching points are provided at most 11kV/400V transformer locations. There is a high level of interconnection between adjacent 11kV feeders. The reticulation in the CBDs is 100% underground, with cable sizes ranging from 70mm2 to 300mm2, aluminium or copper. In some areas there are express feeder inter-ties of up to 630mm2. In key locations 11kV switch automation is being progressively introduced, and provision for future automation is being provided at less critical locations. This configuration allows quick restoration of supply in fault situations.

226. The 400V network consists of radial circuits with a high degree of interconnection. The interconnection between distribution substations is made at junction boxes located along the 400V circuits. The cable sizes are typically large (up to 0.5 sq. inch copper). The 400V network is 100% underground in the CBDs. Load can be transferred across the 400V network in some locations.

227. The main streets of most towns and suburban centres in Powerco's network have a typical urban network configuration. In these centres the business district is largely or completely underground.

228. Large retail business customers include 88 The Square in Palmerston North, Bayfair in Mt Maunganui and Centre City Shopping Centre in New Plymouth.

RESIDENTIAL NETWORKS

229. Both 11kV and 400V residential distribution networks (F3 in Tables 4.3and 8.3) are interconnectable radial networks. The level of interconnectability is moderate, commensurate with the reliability requirements. In general, newer areas have underground reticulation while older areas are overhead. In some urban areas, the distance and/or load between switching points is such that Powerco's planning criteria are not fully met.

230. Low-voltage networks in residential areas tend to be extensive, with transformer capacities of around 200kVA typically supplying 50 or more ICPs. Load can be transferred across the 400V network in some locations either through link boxes or through temporary jumpers.

RURAL NETWORKS (F4)

231. The rural network consists of 11kV lines with isolators installed every 1-2km in some regions. This enables flexibility of switching, but presents a maintenance and reliability liability. Generally, 11kV spur lines may be fused with dropout fuses. There is some interconnection between feeders to allow backfeeding in maintenance and fault situations. Feeders are overhead lines on wooden or concrete poles.

232. Line reclosers and sectionalisers are used in rural areas. Typically reclosers are placed at the transition between urban and rural loads and between rural and remote rural loads. Sectionalisers are used on some spur lines. Many reclosers are SCADA-controlled.

233. Low-voltage networks may be short supplying up to around five ICPs and transformer capacities of up to around 100kVA are common.

REMOTE RURAL NETWORKS (F5)

234. Remote rural feeders are generally radial with limited or no interconnection between adjacent feeders. In some areas, 11kV isolators and 11kV dropout fuses are used to provide discrimination and sectionalising under fault conditions. Some remote areas are supplied by two-phase lines, and a small number are supplied by single-wire earth return (SWER).

235. Due to the scattered nature of the population there are no significant rural 400V networks. Typically, the 400V network extends 100-200m under the main distribution voltage lines from the distribution transformer to supply nearby loads. Distribution transformers would typically have a capacity of 15 or 30kVA.

236. Many of the remote rural coastal communities have been undergoing subdivision, leading to stress on the electricity networks that supply them, particularly during holiday periods. Furthermore, there is a tendency that the consumers moving to these communities are used to urban supply reliability and have consequent high expectations.