Electricity Distribution Business Pricing Methodology Effective from 1 April 2016

31 March 2016

Summary of our prices from 1 April 2016

Why is this document important?

The purpose of this document is to describe Electra Limited's (referred to as "Electra", "we", or "our") approach to setting electricity distribution prices from 1 April 2016. The setting of prices is important for all stakeholders in Electra (including consumers) as it enables Electra to recover the revenue it needs to safely and reliably provide electricity network services to electricity consumers in the Horowhenua and Kapiti Coast region.

Electricity distribution prices are likely to evolve over the next five to ten years

It is clear that over the next decade, the use of alternative energy sources (such as solar photovoltaic generation and battery storage) will increase. We need to ensure that the operation of our network, and the services that we provide (and the prices we charge for those services), are appropriate to meet the future needs of consumers.

Consistent with the views of the Electricity Authority, it will become increasingly important for prices to reflect the cost of the services being provided by an electricity distribution business. In the face of alternative energy sources, there is an increasing need to minimise inefficient consumption and investment decisions by both consumers and distribution businesses, and a move towards more cost-reflective and service-oriented prices will assist this purpose.

In the face of these potential changes, we have developed a pricing strategy to guide the development of our electricity distribution prices over the coming years. In summary, our pricing strategy is:

> Electra will progressively introduce service- oriented and cost-reflective pricing to fairly recover the full cost of the network from all customers that use the network. This is planned to occur over the next 5 years, but we will move faster or slower as necessary.

Our pricing strategy includes six key actions (which are presented in Section 3.3) and four Electra-specific pricing principles (which are presented in Section 3.2) to guide the implementation of the strategy.

Our pricing strategy has a near-term focus on achieving greater cost-reflective, service-oriented, pricing which we believe will provide the foundation to manage the impact of the growth in alternative energy sources.

The changes to our prices from 1 April 2016 are the start of this evolution

Our prices that apply from 1 April 2016 include a number of small changes that are consistent with our pricing strategy. Key changes to our prices for this coming year are set out in Table 1 below.

Table 1: Changes to our prices to apply from 1 April 2016

Change	Impact on consumers
Opening of the Time of Use price option to all customers.	As part of our pricing strategy, we have opened the Time of Use price option to all groups of consumers (this was previously limited to only medium and large consumers). Consumers should

Change	Impact on consumers
	be able to access this price option using a smart meter.
Transfer existing medium consumers on the Time of Use price option to the Standard price option	Medium consumers that are presently using the Time of Use price option are being encouraged to transfer to the Standard price option, which has been designed for larger volume users.
Changes to the description of the pricing options to align with the ENA's pricing working group recommendations.	We have standardised our descriptions of our pricing options to enable better comparison of prices between Electra and other electricity distribution businesses.
Prices set to recover our target revenue for the 2016/17 financial year.	Total target revenue has increased by around 5%, which reflects increases in transmission charges, depreciation and return on investment.
New Community Lighting Maintenance price option introduced	A separate price option has been created to recover the cost of maintaining community lighting. The Community Lighting distribution price option has decreased as a result.
Details of our pricing strategy have been included in this pricing methodology	The inclusion of our pricing strategy should enable consumers to gain a greater understanding of the possible changes to our electricity distribution prices over the coming five to ten years.
The content and structure of this methodology statement have been updated to improve readability.	The new format and content of this pricing methodology should enable consumers to gain a greater understanding of how we set our prices.

The new prices that apply from 1 April 2016 are set out on the following page. We have included the 2015 prices for comparison purposes.

Our pricing methodology complies with the regulatory requirements

We have reviewed our pricing methodology against the relevant regulatory requirements, and having considered the nature of our network and the practical evolution of our prices to manage disruptive change for our consumer, we are comfortable that our approach complies with:

- The Electricity Authority's pricing principles;
- The Electricity (Low Fixed Charges Price Options for Domestic Consumers) Regulations 2004 (LFC Regulations);
- The Electricity Industry Participation Code, Part 6 - pricing of distributed generation;
- The Electricity Industry Participation Code, Part 12A - distributor use-of-system agreements and distributor prices.

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Our prices that apply from 1 April 2016

Table 2: Electra's electricity distribution prices to apply from 01 April 2016

Electricity Network Prices Kapiti Coast and Horowhenua: Effective 1 April 2016

Electra owns and operates the electricity lines and distribution assets in the Kapiti-Horowhenua region.

Electra invoices these prices to Electricity Retailers, who then include these in your regular electricity bill.

Electra Electricity Network Prices from 1 April 2016 compared to existing prices (excluding GST)

Users (Est)	Price Code	Price Option	Price Option Component	Time Zone On		Line Function cents / unit		Transmission cents / unit		Total cents / unit	
						Existing	New	Existing	New	Existing	New
44,118	F	**Fixed Price - Low User Options**		All	cents/day	**5.00**	**5.00**	**10.00**	**10.00**	**15.00**	**15.00**
40,036	A	**Uncontrolled (formerly Anytime)**		All	cents/kWh	9.49	9.74	2.80	3.26	12.29	13.00
23,875	M	**Controlled 20 (formerly Managed Saver)**		As required	cents/kWh	2.32	2.32	1.10	1.28	3.42	3.60
2,558	C	**All Inclusive (formerly Combined)(closed)**		As required	cents/kWh	7.47	7.66	2.28	2.66	9.75	10.32
581	N	**Night (formerly Super Thrifty)**		2300-0700	cents/kWh	0.75	0.75	0.21	0.24	0.96	0.99
2,001	B	**Night Boost (formerly Thrifty)**		2300-0700	cents/kWh	0.94	0.94	0.21	0.24	1.15	1.18
				1300-1600	cents/kWh	0.94	0.94	0.21	0.24	1.15	1.18
1616	DN	**Day/Night**	Night	2100-0700	cents/kWh	0.90	0.90	0.21	0.24	1.11	1.14
	DD		Day	0700-2100	cents/kWh	10.36	10.63	2.81	3.28	13.17	13.91
776	TN	**Time of Use**	Night	2300-0700	cents/kWh	0.75	0.77	0.21	0.24	0.96	1.01
	TP	**(formerly Triple Saver)**	Peak	0700-1100	cents/kWh	12.28	15.12	2.72	3.17	15.00	18.29
				1700-2100	cents/kWh	12.28	15.12	2.72	3.17	15.00	18.29
	TO		Off peak	1100-1700	cents/kWh	1.27	1.56	1.10	1.28	2.37	2.84
				2100-2300	cents/kWh	1.27	1.56	1.10	1.28	2.37	2.84
223	EX	**Export**		All	cents/kWh	0.00	0.00	0.00	0.00	0.00	0.00
	U	**Street Lighting**		Timetable		6.83	7.01	2.78	3.24	9.61	10.25
	U	**Community Lighting**		Timetable		8.31	7.01	2.78	3.24	11.09	10.25
	CM	**Community Lighting Maintenance Fee**		Each Fitting	cents/day	0.00	15.00	0.00	0.00	0.00	15.00
178	S	**Fixed Price - Standard Option**		All	cents/day	**70.00**	**70.00**	**20.00**	**50.00**	**90.00**	**120.00**
178	SN	**Standard**	Night	2300-0700	cents/kWh	0.70	0.70	0.21	0.21	0.91	0.91
	SP	**(formerly Standard**	Peak	0700-1100	cents/kWh	8.63	8.63	2.88	2.88	11.51	11.51
		Industrial)		1700-2100	cents/kWh	8.63	8.63	2.88	2.88	11.51	11.51
	SO		Off peak	1100-1700	cents/kWh	1.19	1.19	1.10	1.10	2.29	2.29
				2100-2300	cents/kWh	1.19	1.19	1.10	1.10	2.29	2.29

<u>Power Factor Premium</u>

This applies to commercial customers. Where the power factor is less than 0.95, Electra reserves the right to impose a power factor premium. The premium will be based on a multiplier of 2% of the monthly total Network price for every 0.01 power factor below 0.95 lagging.

<u>Price Option Naming</u>

Some price options have been renamed to conform to standard industry terminology. In the table above, the previous names are shown in brackets beside the new names.

<u>All Inclusive Option</u>

The All Inclusive option is no longer available except to existing users. Existing users must have electric hot water which (if required) is able to be controlled by Electra, plus either a Night or Night Boost meter.

<u>Time of Use Option</u>

This option (formerly Triple Saver) had previously been only available to customers using more than 25,000kWh per annum. It is now available to any customer.

<u>Export</u>

For those who are generating electricity on their premises and exporting some or all of this into Electra's distribution network.

<u>Sales Discount</u>

A Sales Discount will be credited to the current customer at each metered supply point (ICP) at the discount date of 31 January 2017. The discount will be $30.00 plus 13% of the ICP's total fixed and variable Line and Transmission prices for the previous twelve months

Content

1. About Electra

1.1 What we do

Electra owns and operates the local electricity distribution network in the Kapiti and Horowhenua regions. The network distributes around 400 Gigawatt hours (GWh) of electricity each year from the national grid to approximately 44,296 consumers. We provide the electricity network that electricity retailers use to supply electricity to consumers.

Electra is owned by its consumers through the Electra Trust, which appoints Directors and holds all of the shares on behalf of the consumers connected to the network.

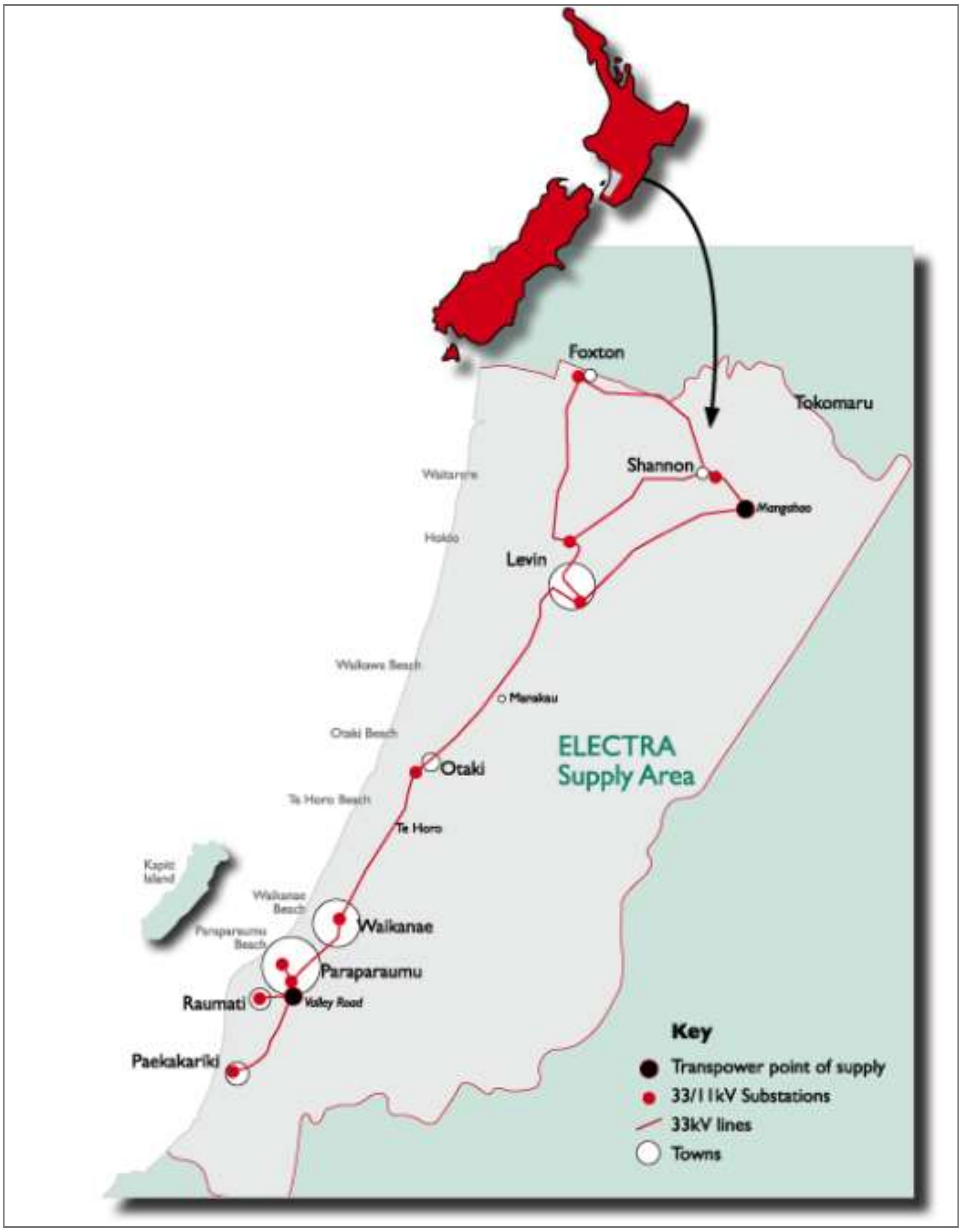


Figure 1: Electra's network supply area

1.2 About our network

Our electricity network supplies a relatively compact geographic area of around 1700 square kilometres. Our network assets are concentrated along the coast, in order to supply the towns from Paekakariki to Foxton. Paraparaumu and Levin are the largest of these towns. Our network is also spread through the rural areas of the Horowhenua and Kapiti Coast where it supplies farms and rural communities.

We receive our electricity supply from the national grid from two Transpower Grid Exit Points ("GXPs"). Our northern area (Horowhenua) takes 33kV supply at the Mangahao GXP. The southern area (Kapiti) takes 33kV supply at the Paraparaumu GXP. While Transpower does not permit continuous connection between these GXPs, load is transferred between north and south to meet operational requirements. The two regions are therefore treated as one network for pricing purposes.

A meshed 33kV sub-transmission network extends from the two GXPs to the main population centres (see Figure 1). This sub-transmission network supplies a series of 33/11kV substations located across the network. From these substations, 11kV distribution lines and cables extend across the region. The electricity from the 11kV distribution system is reduced to 400V through distribution transformers and reticulated around streets and roads. Almost all consumers are connected to this low voltage network (with a very small number of large consumers connected to the 11kV distribution system).

The upgrade to the Paraparaumu GXP is expected to be cost neutral to Electra over the life of the asset. This is part of an arrangement between Electra and Transpower. However, any additional Transpower charges associated with Mangahao, as well as costs associated with our own corresponding network investments, will need to be recovered from consumers unless utilisation of existing capacity on the network can be reduced.

Our Asset Management Plan (which is released each year in April) provides details of what we are planning to do to the network to continue to provide a safe and reliable supply of electricity. The Asset Management Plan specifies the work that we are planning to undertake on the network, and the extent of this work will influence our prices over time.

2. How we set our prices

2.1 Approach to setting prices

Each year we review and set the prices we charge for the use of the electricity network. This is an iterative approach as shown in Figure 2.

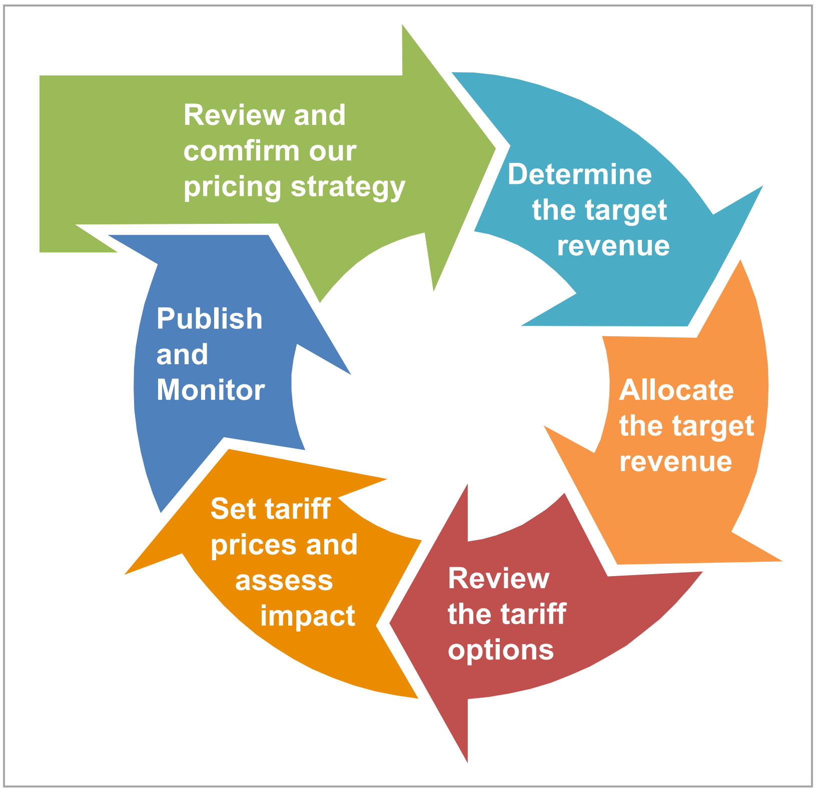


Figure 2: Electra's pricing review cycle

Our pricing review process comprises the following key steps:

- **Reviewing and implementing our pricing strategy:** We review our pricing strategy and associated implementation plan to guide the evolution of our consumer groups and price options (refer to Section 3);
- **Setting the target revenue:** We calculate our target revenue to be recovered through prices (refer to Section 4);
- **Allocating the target revenue to consumer groups:** We review and confirm our consumer groups and allocate the target revenue to the consumer groups consistent with our cost of supply model (refer to Section 5);
- **Reviewing price options and design:** We review and confirm the price options to be applied to each consumer group (see Section 6);
- **Setting the price charges and assessing the impact on consumers:** We calculate charges under each price option and assess the impact of any changes on consumers (see section 7);
- **Publishing and monitoring:** We prepare our pricing methodology and publish this information on our website to transparently disclose our prices, and our approach to pricing.

2.2 Regulatory cconsiderations

Electra's network is a "natural monopoly". That is, it is considered more economically efficient for one network to supply all consumers, due to economies of scale. Accordingly, Electra is not directly exposed to competitive forces that drive markets to deliver improved efficiency and services. Legislators typically regulate such businesses to ensure price and quality outcomes are consistent with competitive markets. However, consumer ownership provides the necessary incentives to ensure Electra delivers an efficient and reliable service to its consumers (who are also its owners) at a fair price. This was formally recognised in 2008 when Electra was exempted from price and quality regulations applying to electricity distribution networks under Part 4 of the Commerce Act 1986, as administered by the Commerce Commission.

While exempt from direct price and quality control, we are subject to regulatory oversight in the form of information disclosure regulation. This pricing methodology is required to be disclosed under the Commerce Commission's Information Disclosure Determination. As part of these requirements, we must describe the extent to which our pricing methodology is consistent with the Electricity Authority's distribution pricing principles (see Appendix One. These principles provide guidance on economic concepts and market considerations, which are applicable for setting efficient network prices.

We must also comply with the following regulations that affect pricing:

- The Electricity (Low Fixed Charges Price Options for Domestic Consumers) Regulations 2004 (LFC Regulations): These require Electra to offer a price option to domestic consumers (using less than 8,000kWh per annum) that has a fixed daily price not exceeding 15 cents.
- The Electricity Industry Participation Code, Part 6 - pricing of distributed generation. Any charges applying to distributed generation (DG) connections must not exceed the incremental costs of connecting this DG to the network, including any avoided costs.
- The Electricity Industry Participation Code, Part 12A: We must consult with retailers on any changes to pricing structures.

3. Our pricing strategy

3.1 The electricity supply industry is likely to change over the coming decades

Over the past 12 months we have been considering the current and future changes to electricity production and usage. In particular we have been considering how our electricity network, and how we charge for the use of our electricity network, should evolve to keep pace with these changes.

It is likely that over the next decade the use of alternative energy sources (such as solar photovoltaic generation and battery storage) will increase. While our current view is that the uptake of alternative energy sources will be modest, we need to ensure that the operation of our network, and the services that we provide (and the prices we charge), are appropriate for the future needs of consumers.

The supply of electricity line services (i.e. what we do at Electra) is regulated and the regulator is seeking efficient outcomes, which includes a drive for electricity distribution businesses to price the services they provide in a cost-reflective manner. A move to cost-reflective pricing over time is important, as it will minimise inefficient consumption and investment decisions by consumers and distribution businesses.

3.2 We have developed a set of Electra-specific pricing principles

The emergence of alternative energy sources, changes in consumer demands, and an increased regulatory interest in pricing issues, has led to a renewed focus on electricity line pricing. In response to these factors, we have developed four pricing principles that we will use to guide the development of Electra's pricing strategy and the implementation of pricing changes over the coming years.

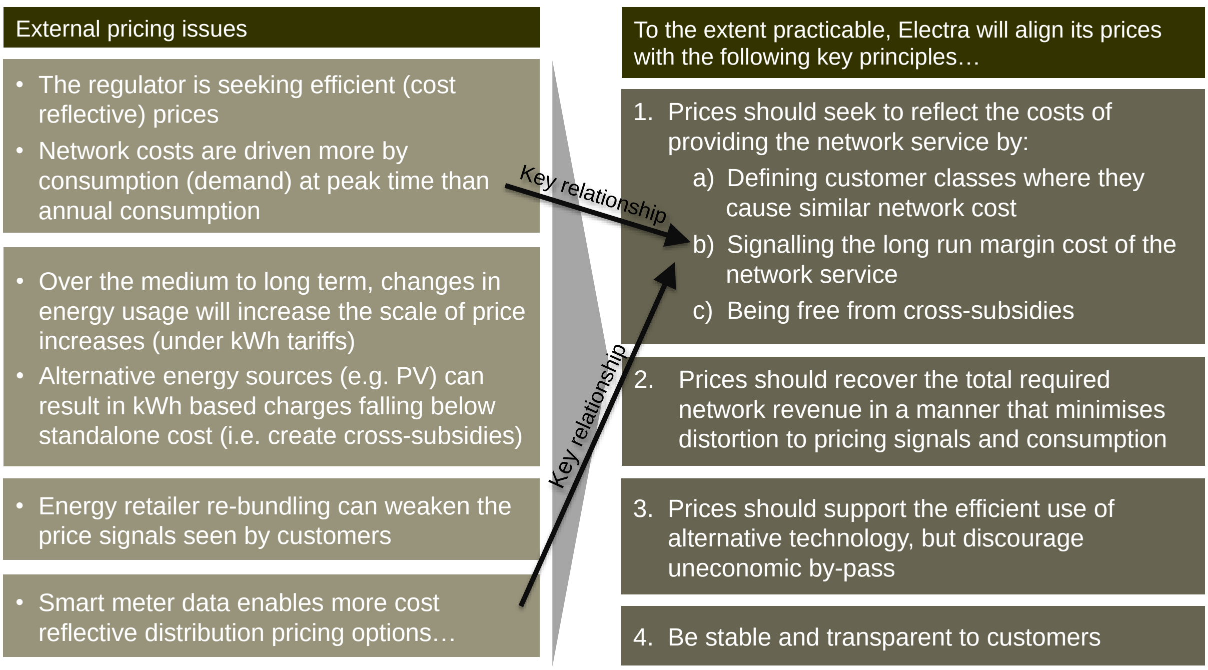


Figure 3: Electra's pricing principles

3.3 We have developed our pricing strategy to guide the evolution of our prices

In response to the potential changes outlined in Section 3.1, we have developed a distribution pricing strategy to guide the evolution of our prices in a manner that:

- Implements Electra's pricing principles;

- Is consistent with Electra's corporate pricing objectives; and,
- Responds to the external issues (namely the uptake of alternative energy sources).

Balancing these factors will enable Electra to evolve its prices ahead of any pending change in electricity production and consumption, while continuing to deliver a high level of service to customers and meeting the needs of the regulator.

The overarching distribution pricing strategy:

Over the next five years, Electra will progressively introduce service-oriented and cost-reflective pricing that fairly recovers the full cost of the network from all customers that use the network

To achieve this strategy, Electra will…

1. Consolidate the low user and medium user price options to a time-of-use price option (which includes a low fixed-charge option).
2. Update the cost of supply model and calculate the long run marginal cost for the network.
3. Seek to recover the long run marginal cost from the variable charge of the price.
4. Introduce a demand and/or capacity service charge across all customer groups.
5. Provide customers with full transparency so they can see Electra's service-oriented prices.
6. Monitor the uptake of alternative energy sources and advance or defer the timing as necessary.

3.4 Our pricing strategy is consistent with Electra's statement of corporate intent

Electra's pricing strategy must be consistent with the statement of corporate intent ("SCI") that defines the overall direction and performance expectations for Electra. We developed a series of corporate pricing objectives (refer to Appendix Two for further details) based on the SCI and "tested" the pricing strategy to ensure that it was consistent with the overall direction for the business. We were satisfied that the pricing strategy was consistent with the corporate pricing objectives, and hence the SCI.

3.5 Strategic implications for prices from 1 April 2016

The key changes that will be seen by customers from 1 April 2016 will be:

- Opening of the current Time of Use price option (formally called the Triple Saver price option) to all customers;
- Changes to the wording of the pricing options to align with the ENA's pricing working group recommendations.

3.6 Implications for prices in subsequent years

The key changes that could be seen in subsequent years are:

- The adoption of a new cost of supply model, which will include an assessment of our long-run marginal cost;
- The introduction of service-based descriptions;
- The consolidation of Electra's pricing options;
- The introduction of a demand and/or capacity charge component.

4. The amount of revenue we need to operate the electricity distribution network

4.1 Target revenue requirement for 2016/17

We determined our target revenue requirement from our Asset Management Plan and our budgeting process. The target revenue is the amount of money we need to safely and reliably provide an electricity network service to all electricity consumers in the Horowhenua and Kapiti Coast regions. The target revenue provides funding for our operating costs, a return to our consumer owners, and capital for reinvestment into the network.

Total target revenue has increased by around 5%, which reflects increases in transmission charges, depreciation and return on investment.

Our estimate of target revenue for the 2016/17 financial year is set out in Figure 4 alongside the 2015/16 target revenue, which is provided for comparison purposes.

Figure 4: Target revenue requirement

Component of target revenue	2015/16	2016/17	Change (%)
Transmission charges	$9.50m	$10.45m	10%
Operating and maintenance	$7.53m	$7.22m	(4%)
Administration and overheads	$4.29m	$2.67m	(38%)
Depreciation	$8.73m	$9.40m	8%
Return on Investment (before tax and posted discount)	$8.24m	$10.46m	27%
Total target revenue	**$38.29m**	**$40.21m**	**5%**

We discuss the components of target revenue below.

4.2 Transmission charges

Our target revenue (and hence our prices) includes the charges we pay Transpower for transmission services, and the avoided cost of transmission that we pay some local generators. These charges have increased over 2015/16 due to changes in transmission charges.

Transmission services relate to the transportation of electricity from the electricity generators (e.g. the hydro power stations, geothermal power stations and wind farms) to the Mangahao and Paraparaumu GXPs that supply Electra's electricity network.

The transmission charge component of the target revenue includes the following Transpower-related charges:

- Interconnection Charges: based on Electra's relative contribution to Regional Coincident Peak Demand (RCPD) in the Lower North Island region of the transmission grid;
- Connection Charges: for the provision of connection assets at the two GXPs from which Electra receives supply from the grid;
- New Investment Agreement Charges: in relation to new connection assets.

Transpower also calculates rental rebates and returns these to distributors over the pricing year. As these are not known at the time of setting prices, Electra estimates the rebates on an annual basis and includes this credit in the transmission revenue requirement. Any additional rental rebates received above this estimate are returned to consumers through sales discounts. We carry the risk of any deficit.

In relation to the avoided cost of transmission included in the target revenue, Electra is responsible for paying all transmission charges associated with the Mangahao GXP. There is a generating station located at Mangahao and it reduces the demand placed on the transmission network (it reduces the RCPD at the GXP) and therefore reduces the total charges payable to Transpower for transmission services. In recognition for this service we pay the Mangahao power station a share of the savings (i.e. the avoided cost of transmission). We also retain some of these savings, which is a benefit to the consumers on the Electra network.

4.3 Operating and maintenance csots

The operating and maintenance costs included in the target revenue are obtained from Electra's Asset Management Plan (AMP) forecasts. The AMP specifies, in some detail, our plans for the maintenance and development of the network, and includes the forecast cost for these activities. Operating and maintenance costs have reduced over 2015/16 due to continued efficiency improvements.

4.4 Administration and overheads csots

Administration and overhead costs are incurred in running the distribution business activities of Electra. These costs are driven by our requirement to manage the non-engineering aspects of the business, which includes customer management, regulatory management, finance, information systems, general management, governance, regulatory compliance, and industry levies. We obtain these costs from our AMP. Administration and overhead costs have reduced materially due to an increase in the allocation of costs to other aspects of the business.

4.5 Depreciation

Depreciation reflects the "return of capital" from the consumption of economic life of the network assets. This charge is a standard calculation of depreciation and is based on the useful economic life of the assets. As our network is constantly being renewed and replaced, the revenue derived from depreciation is typically reapplied to fund new capital projects on the network. The extent of these capital projects is shown in our AMP. Depreciation has increased over 2015/16 as a result of increases to Electra's asset base (which drives higher depreciation), and due to the recognition of disposals that result from some planned renewal projects.

4.6 Return on investment (after applying the posted discount)

The return on investment component of the target revenue reflects the gross (i.e. prior to the payment of tax) financial return on capital investment in the network assets. The level of return being targeted reflects Electra's cost of capital, this is, the level of return appropriate for its shareholders (the Electra Trust and its consumer beneficiaries) and covers the cost of debt funds. For the purpose of this target revenue calculation we have deducted the discount (which is the return provided to consumer owners). The return on investment has increased as Electra seeks to recover its cost of capital from its network assets.

5. Allocation of target revenue to consumer groups

5.1 Consumer groups

The basis for the consumer groupings we have adopted in our 2016 pricing methodology is unchanged from last year. We have three primary consumer groups, with one transitional consumer group:

Table 3: Consumer groups

Consumer group	Definition
Small consumers	Consumers using less than 25,000kWh per annum (which will rise to 40,000kWh upon the removal of the medium consumer group).
Medium consumers*	Consumers using between 25,000kWh and 40,000kWh per annum.
Large consumers	Consumers with time-of-use (“TOU”) meters using more than 40,000kWh per annum.
Lighting	Streetlighting and community lighting.

* We have recognised this medium consumer group as we transition large consumers (who are presently on the Triple Saver price option) to the standard industrial price option (which is applicable to large consumers).

We established the three primary consumer groups as part of our 2013 pricing review. We have reviewed these consumer groups during our most recent pricing strategy review and consider that they remain appropriate for pricing purposes.

Further disaggregation of the small consumer group is not warranted, as the load profiles for most consumers in this group are broadly similar in relation to their impact on peak demand (excluding an immaterial number of outliers). In addition, further disaggregation of the small consumer group would have created unnecessary complexity in relation to complying with the low fixed charge (“LFC”) regulations.

Further disaggregation of the large consumer group is also not warranted, as the small number of large consumers, coupled with the diversity of demand, would cause significant additional complexity, with no material benefit.

Street lighting and community lighting is a separate consumer group. This recognises that these connections use dedicated assets (i.e. streetlight circuits) and have unique demand profiles (i.e. at night).

There are no non-standard consumer groups (i.e. defined as applying to less than 4 connections) connected to the network.

5.2 Consumer considerations

Consumer ownership

Electra is owned by its consumers through the Electra Trust. Trust ownership means that surpluses not required for the operation and development of the network and business are returned to consumers by way of electricity sales discounts on their electricity accounts.

Consumer feedback

In November and December 2014, we undertook a survey of our consumers in order to better understand their views on prices, quality of supply, and consumption patterns. We surveyed 300 consumers (both residential and commercial). Consumer feedback included:

- 94% of respondents believed that we provide a reliable service (up from 72% in 2012), with 76% believing that faults were fixed quickly;
- 46% believed that our charges were reasonable.

While the improvement in reliability is pleasing, we are working hard to keep prices affordable, with this year's price increase matching cost inflation expectations.

The survey also highlighted an increasing use of energy efficient products, which is expected to continue to exert downward pressure on consumption. In the short-term, falling consumption means variable prices per kWh will increase in order to recover our annual target revenue.

The survey also highlighted reasonable interest from consumers in alternative forms of energy with 2% of respondents indicating they had installed solar photovoltaic ("PV") supply and 18% suggesting they were considering it. The installation of PV creates both commercial and operational challenges and opportunities for the network, which we need to better understand. Accordingly, we intend to more proactively monitor the uptake of small scale distributed generation (including PV) and analyse the potential network impacts.

Figure 5: Consumer survey results

% of respondents that	Customer type	2012	2013	2015
Use energy efficient light bulbs	Domestic	78%	84%	86%
	Commercial	54%	61%	69%
Use of a heat pump	Domestic	27%	32%	38%
	Commercial	30%	30%	40%

5.3 Cost drivers

Overview of network attributes that influence cost drivers

We have considered the relevant drivers of costs that we are seeking to recover, in order to inform our decisions on consumer groupings, price structures, and the level of charges.

Over 90% of our costs are associated with investing in, maintaining, and operating the network, as well as receiving supply from Transpower's network. The remaining costs are associated with general management and administration. The key cost drivers relevant to setting prices are therefore weighted heavily towards investment in, and operation of, the network.

Key network attributes that influence the quantity of assets and their associated operating costs are:

- The capacity of the network (measured in kVA);
- The length of circuit required to supply consumers (measured in kms);
- The number of consumer connections (measured in ICPs); and
- Consumer-specific asset use.

Table 4: Key network attributes

Network attribute	Value
Consumer numbers (no.)	44,296
Total circuit length (km)	2,256
Consumer density (ICPs/km)	19.63
Zone substation installed firm capacity (MVA)	352
Maximum demand (MW)	89
Energy conveyed (GWh)	402
Energy density (kWh/ICP)	9075

Source: 2015 Information Disclosure

Network capacity

Our network is designed and operated to meet forecast electricity maximum demand up it the level of installed firm capacity, and to provide a level of service (i.e. reliability) consistent with consumers' expectations. As maximum demand reaches installed firm capacity limits, we must consider further investments in network capacity to meet demand. Consumer usage of the available network capacity is therefore a key driver of existing and future network costs.

However, as can be seen in Table 4 above, Electra's network maximum demand of 98MW is well below the zone substation installed capacity of 352MW. This broad measure indicates that the network is not constrained in general terms (from time to time there may be some localised constraints which are addressed as set out in our AMP).

Circuit length

The length of circuit required to transmit electricity from the GXP to consumers is a key driver of network investment costs. Consumers who are further from the main supply areas create relatively higher costs for Electra. However, in practice, the network is relatively compact and extensive meshing of the distribution network in urban centres makes it difficult to distinguish line length for a particular consumer or group of consumers (due to the difficulty in tracking electrical flows). While a demarcation could conceivably be made between rural and urban consumers, such a pricing approach is inconsistent with our Corporate Pricing Objectives. Therefore, while circuit length is a relevant cost driver we have not factored this into our pricing design.

Consumer connections

New connections, and upgrades to connections, drive asset-related and maintenance costs. Electra's network extension policy requires consumers to pay for connection- related asset costs upfront. Each new connection also creates operating and maintenance costs, including network operations and planning, fault restoration, and maintenance and general administration costs. New connections therefore increase operating costs over time, which must be reflected in prices.

Consumer-specific asset usage

Where practical, the network costs that directly relate to a particular consumer or group of consumers are identified and recovered from those parties. This aligns recovery of costs with the beneficiary of those assets. Street lighting and community lighting is a consumer group that has specific assets identifiable and allocated to that group.

In 2013 we considered whether consumer-specific asset use could be better reflected in our pricing methodology. In particular, the use of high and low voltage assets and dedicated equipment (i.e. transformers) was considered. We concluded that there is very little variation in asset utilisation within our consumer base (e.g. less than 0.01% of consumers directly connect to 11kV feeders). For those consumers that require dedicated equipment, this is generally dealt with as part of our network extension policy, rather than through pricing. We therefore consider that there is little benefit in consumer-specific asset pricing, with the exception of street lighting and community lighting.

5.4 Allocation of costs (i.e. target revenue) to consumer groups and price options

Summary of our approach to allocating costs to consumer groups

Consistent with the preceding discussion in Section 5.3, the allocators we apply to allocate costs to consumer groups in our cost of supply model are as follows.

Table 5: Allocators applied in cost allocation model

Cost category	Cost allocator	Rationale
Return on investment, network depreciation, direct costs, rates	A composite allocator is created by allocating regulatory asset base values to consumer groups as follows: Connection assets: ICPs Streetlight assets: directly attributed to street lighting All other assets: Coincident maximum demand	The main cost driver for core network assets is utilisation of installed capacity weighted by the value of that capacity. Streetlight assets are directly attributable to the lighting consumer group, whereas connection assets are associated with number of connections.
Transmission costs	Coincident maximum demand	This recognises that Transpower charges are based on providing supply capacity, determined by the capacity of the GXP and core grid assets.
Indirect costs, depreciation on non-system fixed assets	A 50:50 weighting of ICPs and kWhs	This weighting recognises that larger consumers create relatively higher costs per connection.

Review of cost allocations in relation to the 2016/17 prices

As noted in previous pricing methodologies, having established our initial cost of supply model in 2012 we presently utilise the model to test and inform our pricing decisions.

We have conducted testing of the revenue recovered against the cost of supply model and the results indicate that there is good consistency between costs and revenue for each consumer class (refer to Figure 6). The increases included in the 2016/17 prices have been weighted towards the small consumer class, which has reduced the revenue to cost gaps for that group from 2% in 2015/16 to 1% in 2016/17.

Due to the reallocation of customers between the medium consumer group and the large consumer group, we have considered revenue to cost gap for the combined medium and large consumer group. For the combined medium to high consumer group, revenue to cost differs by 1%.

Figure 6: Cost allocations and revenues

Revenue allocation in 2016/17 Prices	Cost allocation from cost of supply model
Street lighting, 1% Large consumers, 13% Medium consumers, 4% Small consumers, 82%	Street lighting, 1% Large consumers, 11% Medium consumers, 5% Small consumers, 83%

We will consider further weighting of price increases across the small consumer group over coming years to fully align revenue to costs. These refinements are relatively insignificant and we are satisfied that prices broadly align with costs. Our approach is to avoid price shocks, which is consistent with Electra's Pricing Principles and Corporate Pricing Objectives.

6. Price options and design

6.1 Alignment of price option names with the ENA's working group recommendations

As part of our pricing strategy implementation, we have aligned the names we use to describe our price options with the Electricity Networks Association's ("ENA") Pricing Working Group recommendations. The purpose of the changes was to implement industry standardisation, which will enable easier comparison of price options across distribution businesses.

Table 6: Price option name changes

Old name	New name
Small consumers	
Supply Charge	Fixed Price - Low User Options
Anytime/Pay Go	Uncontrolled
Managed Saver	Controlled 20
Combined	All Inclusive
Super Thrifty	Night
Thrifty	Night Boost
Day/Night	Day/Night
Export	Export
Small and medium consumers	
Triple Saver	Time of Use
Supply Charge	Fixed Price - Low User Options
Large consumers	
Standard Industrial	Standard
Supply Charge – Standard Industrial	Fixed Price - Standard Option
Street lighting and community lighting	
Street Lighting	Street Lighting
Community Lighting	Community Lighting
n/a	Community Lighting Maintenance

6.2 Price changes

As part of our pricing strategy implementation, we removed the usage restriction in relation to the Time-of-Use price option. This price option was previously only open to consumers using greater than 25,000kWh per annum, and is now open to all customer classes.

We have also created a new Community Lighting Maintenance fee to recover the cost of maintaining community lighting.

6.3 Price options for 2016/17

Table 7 provides a brief description of each of the price options.

Table 7: Electra's price options

Name	Description	Code	Price component		Unit of measure
Small consumers					
Fixed Price - Low User Options	Daily fixed charge applicable to small consumers	F	n/a		cents/day
Uncontrolled	A standard price for using electricity at any time of the day. Can be used in conjunction with TOU price options. PayGo is the alternative price label for Anytime consumers that are on 'pay as you go' retail prices.	A	n/a		cents/kWh
Controlled 20	A price which consumers may choose for hot water heating (and for other uses) on the basis that supply is able to be interrupted in return for a lower price. Electra is able to switch off load for up to 4 hours each day under this price.	M	n/a		cents/kWh
All Inclusive	Closed	C	n/a		cents/kWh
Night	A night rate between 23:00 and 7:00 reflecting the large amount of available capacity on the network at this time. Designed for hot water, storage heating or under floor heating loads. Uncontrolled rates apply outside of these times. This does not function as a standalone option and must be used in conjunction with another price option.	N	Night only	2300-0700	cents/kWh
Night Boost	As for Night with the addition of an afternoon heating boost.	B	Night	2300-0700	cents/kWh
			Day	1300-1600	cents/kWh
Day/Night	For continuous electricity supply at two time of use prices: a night time rate set for the 10 hours between 21:00 and 7:00; and a peak-rate during the day.	DN	Night	2100-0700	cents/kWh
		DD	Day	0700-2100	cents/kWh
Export	For those that are generating electricity and exporting some or all of this. For monitoring purposes only.	EX	n/a		cents/kWh
Small and medium consumers					
Time of Use	A three rate (peak, off-peak and night) time-of-use option available to all consumers with the ability to move load or otherwise take advantage of price signals.	TN	Night	2300-0700	cents/kWh
		TP	Peak	0700-1100	cents/kWh
				1700-2100	cents/kWh
		TO	Off peak	1100-1700	cents/kWh
				2100-2300	cents/kWh

Name	Description	Code	Price component		Unit of measure
Fixed Price - Low User Options	Daily fixed charge applicable to small consumers	F	n/a		cents/day
Large consumers					
Standard	A three rate (peak, off-peak and night) TOU option which differs from the Time of Use price by higher fixed and lower variable charges. It is targeted at larger commercial consumers by rewarding those able to move load away from peak, or otherwise take advantage of price signals.	SN	Night	2300-0700	cents/kWh
		SP	Peak	0700-1100	cents/kWh
				1700-2100	cents/kWh
		SO	Off peak	1100-1700	cents/kWh
				2100-2300	cents/kWh
Fixed Price - Standard Option	Daily fixed charge applicable to consumers on the standard pricing option	S	n/a		cents/day
Street lighting and Community lighting					
Street Lighting	Connection and management of street lights.	U	Timetable		cents/kWh
Community Lighting	For connection and management of community lighting (e.g. sports fields, shop verandas)	U	Timetable		cents/kWh
Community Lighting Maintenance	This is a new price to recover the costs of maintaining community lighting (which was previously included in the community lighting network price)	CM	Each Fitting		cents/day

6.4 Analysis and discussion on price design

Overall price design elements

Electra's prices are focussed towards the mass market (small and medium consumer group) because the consumer base is dominated by small loads. Domestic and small commercial users represent approximately 98% of connections and over 80% of maximum demand. As a result, Electra has the lowest average use per connection of all New Zealand electricity distribution businesses (i.e. 9,075 kWh per consumer compared to the industry average of 16,306 kWh per consumer).

Mass market connections are low voltage, typically 60 Amp single phase or 40 Amp three phase. Our analysis suggests these consumers have a typical residential demand profile which peaks in the morning and early evening.

Our pricing must also cater for several hundred large commercial loads. In contrast to the mass market, most large commercial loads have time-of-use metering, and much higher levels of annual consumption (ranging from 40,000kWh to more than 3GWh). They also have distinct demand behaviours: many have flat demand across the standard working day, whereas others vary by time of day and season. From a cost driver perspective, large consumers have higher capacity connections and utilise a greater proportion of the installed network capacity relative to the average mass market connection.

All price groups are charged a variable price and a fixed daily charge. Fixed charges and variable prices are separated between distribution and transmission components, which seek to recover distribution and transmission costs, respectively.

Specific prices in the small, medium and large consumer groups incorporate signals which incentivise consumers to move their consumption off-peak and to offer up interruptible load. This aligns our pricing incentives to the key capacity utilisation cost driver and our GXP capacity constraints.

Each price option has been specified to achieve certain objectives. However, we are reliant on electricity retailers fairly reflecting our prices in their retail prices.

Variable charge components

A variable price based on kWh consumption is applied to all price groups. While a charge based on each consumer's relative share of coincident maximum demand would align more closely with the utilisation of network capacity, a consumption charge is preferred because:

- There is a lack of ubiquitous half-hourly metering across the small consumer group;
- It aligns with existing retail pricing structures, which are predominantly based on volumetric charges; and
- It aligns with the LFC regulations.

Time of use charge components

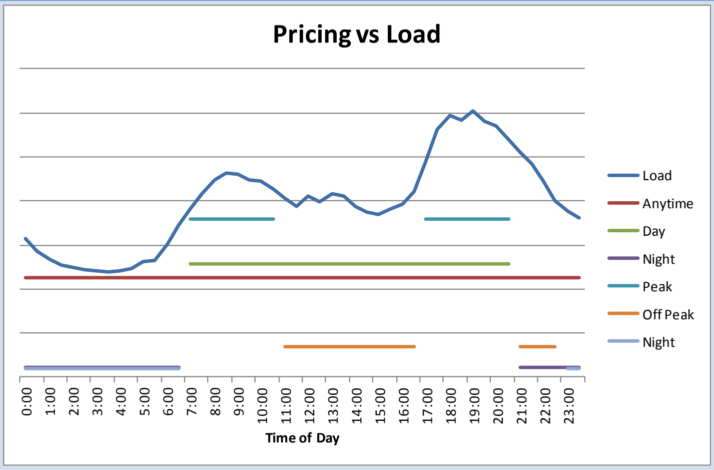
Several of our price options are designed to incentivise efficient use of our existing network capacity by setting higher variable prices at peak periods and lower prices during the shoulders and off peak periods.

Our Time-Of-Use price option is now available to be utilised by retailers for any small consumer with a smart meter.

Figure 6 illustrates our time-of-use price options, usage periods, and how these pricing periods align to our typical daily load profile.

Figure 7: TOU periods and typical daily load profile

Price	Time-of-use Periods
Night	• Off-peak rate from 2300-0700 • Other times charged at the Managed Saver or Combined rates
Night Boost	• Off-peak rate from 2300-0700 • Boost from 1300-1600 • Other times charged at the Managed Saver or Combined rates
Night/Day	• Night rate from 2100-0700 • Day rate from 0700-2100
Time of Use Standard	• Night rate from 2300-0700 • Peak rate from 0700-1100 & 1700-2100 • Off-peak rates from 1100-1700 and 2100-2300



Controlled load price option

Controlled load price options are also offered, such as the Controlled 20 or All Inclusive price options. These allow us to disconnect load for up to four hours a day, typically during times of high demand or in order to allow us to restore network faults.

A variable charge is levied on street lighting and community lighting consumers. This recognises network capacity use as well as the use of dedicated assets such as street lighting circuits and poles. Other consumers are charged under the Uncontrolled price option (often in combination with controlled load price options). Uncontrolled consumers account for 86% of connections and almost 50% of consumption. The Uncontrolled price option is the highest variable price, which recognises that these consumers are able to use the network at any time without constraint.

Fixed charge components

A fixed daily charge is applied to all consumers. We consider that a fixed charge appropriately recognises:

- Investments in existing network capacity;
- Connection cost drivers;
- Our need for revenue stability; and
- The LFC regulations.

Given that a significant number of our consumers are eligible for the low fixed charge option, we opted to apply the 15 cent per day fixed charge to all small and medium consumers.

Transmission charges

Electra on-charges Transpower's costs on a cost-recovery basis. Fixed and variable transmission prices are set to recover transmission costs using forecasts of consumption and connections. This accommodates the different charges relating to off peak and peak pricing.

Power factor charges

We reserve the option to apply an additional charge where a commercial consumer has a power factor materially below 0.95 lagging. The charge will be based on a multiplier of 2% of the monthly total network charges for every 0.01 power factor below 0.95 lagging. This charge allows us to signal the need for improvements in power factors with the ultimate goal of avoiding unnecessary network reinforcement.

Distributed generation (DG) price option

Electra has a small number of DG sites connected to its network (less than 1% of connections). All but two of these are small sites (less than 5kW) which are connected at 400V. We use standard charging for import meters and do not charge for distributing exported energy. We have introduced an export price, which would potentially enable us to do this. Currently, it is set at zero cents per kWh. This has been introduced to help us monitor the uptake of DG on the network.

We currently do not make direct payments to DG for the avoided cost of transmission or distribution as tit is not practical to do so. Avoided costs are recognised by not charging generators for injection into the network. We believe this approach is consistent with the incremental cost pricing principle under Part 6 of the Electricity Industry Participation Code.

The Mangahao power station near Shannon is notionally embedded for transmission purposes, but is not connected to our network and does not use distribution services. We are responsible for paying all connection charges associated with the Mangahao GXP but our consumers share in the avoided Transpower charges that result from the generator reducing peak grid demand at this GXP. ACOT is therefore implicitly recognised in this arrangement.

6.5 Non-standard pricing

We currently do not have any non-standard pricing arrangements. We will assess any requests for non-standard pricing as required.

6.6 Network extensions policy

In addition to distribution prices, consumers are required to fully fund the cost of their own connection assets, at the time of connection. Connection assets include additional 11kV and 400V power lines and cables and transformers required to provide the electrical load and quality of supply sought by consumers. Where these assets are vested with Electra, then we will pay for the ongoing maintenance and operation of the assets. We may also provide a refund to consumers where the required asset upgrade exceeds the consumer's requirements.

Distribution prices do not seek to recover connection costs paid for by consumers under our network extension policy. Further information on our network extension policy can be found on our website at: http://www.electra.co.nz/docs/disclosures/network_extensions__upgrade_policy_disclosure.pdf

7. Setting prices for 2016/17

7.1 Changes included in the 2016/17 prices

We have made changes to a number of prices for the 2016/17 period in order to recover the target revenue increase of 5% mentioned in Section 4.1. Consistent with our pricing strategy and the Electra Pricing Principles, our general approach was to:

- Increase the distribution portion of prices to recover the increase in the distribution network depreciation and return on investment. The increases were applied only to price components that covered the periods of maximum demand (that is, the price increase was not applied to night periods of time-of-use price options);
- Increase the Time of Use peak and off-peak periods to align the total cost recovery to other price options;
- Increase the transmission portion of all prices to recover the increase in transmission costs;
- Set a price to recover the cost of maintaining community lighting in a separate price option, and to reduce the existing network Community Lighting price by a similar amount.

Table 8: Changes included in the 2016/17 prices

Price option	Change	Reason for change
Small consumers		
Fixed Price - Low User Options	No change	n/a
Uncontrolled	Distribution price increased by 2.6%*	To recover the increase in distribution costs
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Controlled 20	Transmission price increased by 16.4%*	To recover increase in transmission costs
All Inclusive	Distribution price increased by 2.6%*	To recover the increase in distribution costs
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Night	Transmission price increased by 16.4%*	To recover increase in transmission costs
Night Boost	Transmission price increased by 16.4%*	To recover increase in transmission costs
Day/Night	Distribution price increased by 2.6%*	To recover increase in distribution costs
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Small and medium consumers		
Time of Use	Peak and off peak distribution component increased by 23%	To move the crossover with Standard closer to 8000kWh
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Fixed Price - Low User Options	No change	n/a
Large consumers		
Standard	No change	n/a
Fixed Price - Standard Option	Transmission daily charge increased from 20c/day to 50c/day	To recover increase in transmission costs
Street lighting and community lighting		
Street Lighting	Distribution price increased by 2.6%*	To recover the increase in distribution costs

Price option	Change	Reason for change
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Community Lighting	Distribution price reduced by 15.6%	Removal of maintenance costs, which are now recovered in new maintenance price option
	Transmission price increased by 16.4%*	To recover increase in transmission costs
Community Lighting Maintenance	New price option	To recover costs for maintenance of Community Lighting separate for the network price option.

* The % increase varied slightly between price options due to rounding.

7.2 Impact of the changes in prices for 2016/17

Table 9 sets out our prices and the proportion of the target revenue forecast to be recovered from each price option in the 2016/17 pricing year. It compares these to 2015/16 prices. The share of target revenue sought from each price option is consistent with 2015/16, with the exception of the higher increase in small consumer prices (when compared to large user prices) to better align the cost recovery with the cost of supply model.

Table 9: Summary of changes in prices

Code	Option	Component	Charge type	2015/16 Prices	2016/17 Prices	Estimated units	Estimated No. users	2015/16 Revenue	2016/17 Revenue	Change
Small consumers										
F	Fixed Price - Low User Options		cents/day	15.00	15.00	44,118	44,118	2,415,461	2,415,461	0%
A	Uncontrolled		cents/kWh	12.29	13.00	194,556,016	40,036	23,910,934	25,292,282	6%
M	Controlled 20		cents/kWh	3.42	3.60	52,129,954	23,875	1,782,844	1,876,678	5%
C	All Inclusive		cents/kWh	9.75	10.32	21,988,880	2,558	2,143,916	2,269,252	6%
N	Night		cents/kWh	0.96	0.99	3,774,649	581	36,237	37,369	3%
B	Night Boost		cents/kWh	1.15	1.18	8,472,487	2,001	97,434	99,975	3%
DN	Day/Night	Night	cents/kWh	1.11	1.14	1,844,957	1616	20,479	21,033	3%
DD		Day	cents/kWh	13.17	13.91	3,000,851	1616	395,212	417,418	6%
EX	Export		cents/kWh	-	-		223	-	-	n/a
Small and medium consumers										
TN	Time of Use	Night	cents/kWh	0.96	1.01	7,989,875	776	76,703	80,698	5%
TP		Peak	cents/kWh	15.00	18.29	13,155,399	776	1,973,310	2,406,122	22%
TO		Off peak	cents/kWh	2.37	2.84	11,311,495	776	268,082	321,246	20%
F	Fixed Price - Low User Options		cents/day	15.00	15.00	776	776	42,486	42,486	0%
Large consumers										
S	Fixed Price - Standard Option		cents/day	90.00	120.00	538	178	176,733	235,644	33%
SN	Standard	Night	cents/kWh	0.91	0.91	20,544,711	178	186,957	186,957	0%
SP		Peak	cents/kWh	11.51	11.51	30,011,181		3,454,287	3,454,287	0%
SO		Off peak	cents/kWh	2.29	2.29	29,425,394		673,842	673,842	0%
Street lighting and community lighting										
U	Street Lighting		cents/kWh	9.61	10.25	3,181,130		305,707	326,066	7%
U	Community Lighting		cents/kWh	11.09	10.25	478,999		53,121	49,097	-8%
CM	Community Lighting Maintenance Fee		cents/day	-	15.00			-	1,538	n/a
Target Revenue								**38,386,486**	**40,207,452**	**5%**

7.3 Sales discount applicable for 2016/17 prices

Electra credits consumers with a discount each year. In 2015/16 we posted this discount in our pricing schedule so that consumers have greater transparency and certainty over their total net electricity costs.

The sales discount will be credited to the consumer connected to each metered supply point (ICP) on 31 January 2017. The value of the discount will be $30.00 plus 13% of each connection's total fixed and variable line and transmission charges for the previous twelve months.

Appendix One: Consistency with the Electricity Authority's pricing principles

Pricing principle	(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 standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;
Compliance	This principle requires that prices are subsidy free where they fall within the range of incremental cost and stand alone cost, as illustrated by the following equation. Incremental Cost ≤ Prices ≤ Stand Alone Cost **Incremental Cost** Incremental cost means the additional cost incurred in connecting one more consumers to the network. This is likely to comprise connection costs, any costs associated with reinforcing the network in relation to that connection, as well as additional administration, operating and maintenance costs. Our prices are close to the average cost for typical consumers in each customer class, hence prices are greater than incremental costs. However, our analysis suggests that on average over the last ten years, a new connection contributed to a $193 per annum real increase in operating costs, with only a marginal increase in the cost of capital. As can be seen in Table 10, the prices payable for different consumers are well above these figures. **Standalone cost** The standalone cost means the cost to provide services to a consumer (or group of consumers) on a standalone basis, either from a standalone network or alternative energy supply. What this cost looks like depends on the location of the consumer relative to the GXP. We estimate that a constant load greater than 5MW and closer than 2km to a GXP would be required to make bypass cheaper than our existing prices. The annualised cost of this would be in the order of $100,000. The standalone costs for smaller consumers would still be significant due to the infrastructure required to transform and transport electricity from 33kV (at the GXP) to 400V to enable supply to a consumer. Hence, for a typical consumer it is obvious that our prices are significantly below the standalone cost. **Rural/urban cross-subsidy** A cross-subsidy could potentially arise from not explicitly recognising circuit length as a cost driver in prices. As discussed earlier, the only discernible cross-subsidy that is likely to arise in relation to circuit length is between rural and urban consumers. While consumers in urban areas could be subsidising rural consumers due to relatively higher connection density, we do not consider that disaggregating rural and urban consumers for pricing purposes is beneficial for the following reasons: • Rural circuits, poles, and equipment are used by urban consumers as electricity may flow through sub-transmission and distribution circuits to urban centres. • Our network area is relatively compact so rural areas are close to urban areas. • Electra does not differentiate service quality by location. Network reliability standards are based on the aggregated load for all consumers supplied by the relevant section of the network. Fault response times are similar for rural and urban connections because all connections are located within 30 minutes drive of a depot.

	• The Electricity Industry Act 2010 includes provisions for regulations to be applied to distributors that would limit price increases in rural areas.
Pricing principle	**(ii) having regard, to the extent practicable, to the level of available service capacity; and**
Compliance	We group consumers into small, medium and large consumer groups because they use service capacity differently. Lighting is also a separate consumer group in recognition of the specific demand profile of this group. The Electra Network is relatively unconstrained (as can be seen by the low level of system development capex included in our Asset Management Plan). Hence, presently we do not need to signal the economic cost of the available service by way of scarcity pricing or other such pricing mechanisms. However, we are increasing the use of differential prices for peak/off-peak and day/night loads, which provide consumers with general signals in relation to periods of peak demand that are likely to drive costs over the long-term. Similarly, our controlled tariff option rewards consumers that offer up interruptible load. We have recently focused on increasing the peak/day price signal to encourage consumers to move consumption to off-peak periods.
Pricing principle	**(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.**
Compliance	We intend to undertake more detailed work to calculate our long run marginal cost. We intend to use this information when considering future price changes. Our preliminary view is that our long run marginal cost will be low when compared to our fixed costs, hence they would significantly under recover our target revenue. The development of our long run marginal cost is included in our pricing strategy mentioned earlier in this report. This work is not presently a high priority due to the very unconstrained nature of the Electra Network, hence the low long-run marginal cost. With that said, we recognise that consumption based charges provide a limited price signal regarding the impact of additional usage on future investment costs. To the extent practical we are presently using prices to signal the costs of meeting peak demand and to encourage consumers to consider the benefits of moving demand away from peak periods. A number of our current price options incorporate higher peak time prices and with lower prices during off-peak and shoulder periods (for example, under the Day/Night, Time of Use, Standard, Controlled 20, Night, and Night Boost tariff options). These price options provide signals to consumers of the long-term benefits of moving consumption away from peak periods. In recent years, we have increased peak prices, relative to off-peak prices, and controlled charges in order to increase the incentives to reduce peak-time demand.
Pricing 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.**
Compliance	We intend to undertake more detailed work to calculate our long run marginal cost. We intend to use this information when considering future price changes. Our preliminary view is that our long run marginal cost will be low when compared to our fixed costs, hence they would significantly under recover our target revenue. The development of our long run marginal cost is included in our pricing strategy mentioned earlier in this report.
Pricing	**(c) Provided that prices satisfy (a) above, prices should be responsive to the**

principle	**requirements and circumstances of stakeholders in order to:** **(i) discourage uneconomic bypass;**
Compliance	Our pricing methodology combined with the nature of our consumer base has not resulted in any uneconomic bypass of the network. We estimate that a constant load greater than 5MW and closer than 2km to a GXP would be required to make bypass cheaper than our existing prices. We do not have any connections which meet these criteria. At that level of load, system bypass would not only be economic but probably appropriate for the customer. We remain open to discussing alternative pricing arrangements with large consumers that are presented with bypass opportunities.
Pricing principle	**(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**
Compliance	We have no non-standard pricing arrangements. In reality, the nature of our network and consumer base does not allow for differences in the level of quality, hence there is no justification for non-standard terms. To the extent practical, requests for specific levels of service (e.g. the provision of dedicated equipment) are typically dealt with under our network extensions policy. This policy gives consumers the discretion to select the assets and hence quality of supply that meet their requirements, with incremental asset costs met by the beneficiary. We recover the cost of maintaining the asset through our normal revenue stream.
Pricing principle	**(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.**
Compliance	Our Controlled 20, Night, and Night Boost price options provide incentives to consumers to invest in night store equipment and controllable hot water cylinders. This effectively provides for a consumer demand response that reduces usage during times of network congestion. Distributed generation ("DG") is not charged for distribution services. This encourages connection of DG, consistent with Part 6 of the Electricity Industry Participation Code. However, we will continue to review the impact of DG uptake on the network through the Export price option. The GXP sharing arrangement with thevMangahao hydro scheme, which is notionally embedded in our network, acknowledges this plant as a transmission alternative. In return, our consumers share in transmission cost savings arising from local generation. This contractual arrangement is an example of a transmission alternative that lowers prices to consumers.
Pricing principle	**(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.**
Compliance	We have considered the feedback on our 2014/15 pricing methodology. We have also considered the feedback on our 2013/14 pricing methodology as part of the Electricity Authority's review and have revised this document in order to improve the transparency of our pricing methodology. We also regularly review the structure of this document to improve it. We have transitioned price increases over multiple years to avoid price shock. For example, we have increased the content of the Time of Use price option (formerly Triple Saver) over a number of years.

Pricing principle	(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.
Compliance	Our relatively simple price options ensure low transaction costs for all. We have a bias towards price option simplicity which minimises transaction costs for retailers. All retailers operating on Electra's network pay the same prices. All consumers are able to remain on their current price option or choose another more suited to their needs.

Appendix Two: Electra corporate pricing objectives

Introduction

The emergence of alternative energy sources, changes in consumer demands, and an increased regulatory interest in pricing issues, has led to a renewed focus on electricity line pricing. This increased focus has led Electra to undertake a strategic review of distribution line pricing arrangements with a view to developing a long-term line pricing strategy.

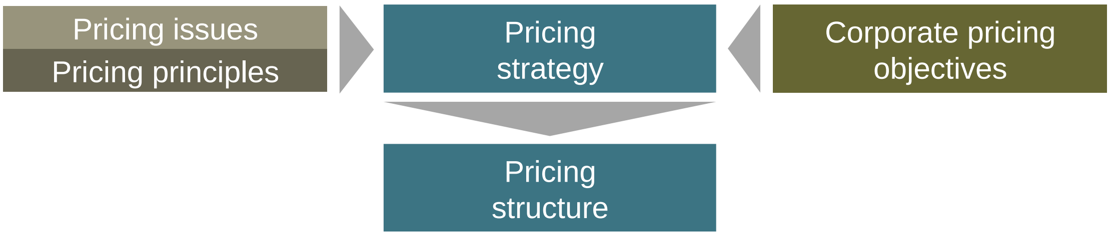


Figure 8: Drivers of the pricing strategy and pricing structure

Corporate pricing objectives

Electra's statement of corporate intent ("SCI") defines the overall direction and performance expectations for the Electra Network. For the SCI we have developed a series of corporate pricing objectives. These are statements that we believe the pricing strategy needs to be "tested" against to ensure that it will satisfy Electra's corporate objectives.

	Corporate pricing objective	Supports Electra with….
Efficiency objectives	1. Price structure should be consistent with the long-life assets and the long period over which Electra will recover its costs	Delivering sustainable returns over the long-term
Efficiency objectives	2. Electra's prices should encourage the efficient use of, and Electra's efficient investment in, the network	Improving efficiency and maintaining competitiveness
Efficiency objectives	3. Prices should not impede the implementation of new technology	Facilitating innovation that improves efficiency
Fairness objectives	4. Price changes should consider the impact of large (upward and downward) short-term variations in the charges seen by individual customers or classes of customers	Fairness to customers
Fairness objectives	5. For each class of customer, prices should fairly reflect costs of providing the service to those customers	Fairness to customers
Fairness objectives	6. Prices should change gradually over time	Fairness to customers
	7. The pricing structure shall comply with relevant legal and regulatory requirements	Being a good corporate citizen

Figure 9: Proposed corporate pricing objectives

Appendix Three: Glossary

We have sought to present our pricing methodology using standard industry terminology and to include sufficient information to enable pricing decisions to be readily understood by consumers. This glossary is provided for the convenience of the reader.

Term	Meaning
2015/16	The year starting 1 April 2015 and ending on 31 March 2016
2016/17	The year starting 1 April 2016 and ending on 31 March 2017.
ACOT	Avoided Cost of Transmission: The difference between actual transmission costs and theoretical transmission costs if certain mitigation (e.g. Distributed Generation) is not present.
AMP	Asset Management Plan: A record of the company's plans to manage the network to provide a specified level of service.
Coincident Maximum Demand (CMD):	Relative demand (typically expressed in kWs or kVA) of a particular consumer or consumer group at the GXP system peak (i.e. as measured by system maximum demand).
Commerce Commission	Responsible for the economic regulation of electricity distribution businesses as provided for under Part 4 of the Commerce Act 1986.
Electricity Authority (EA)	Responsible for regulation of the electricity market as provided for under the Electricity Industry Act 2010.
GXP	Grid Exit Point: The point at which Electra's network is deemed to connect to Transpower's transmission network.
ICP	Installation Control Point: A point of connection on a local network which the distributor nominates as the point at which a retailer will be deemed to supply electricity to consumers (i.e. a consumer connection point).
Information Disclosure Determination	As set out in the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, issued 1 October 2012 (Decision No. NZCC22).
kVA:	Kilo Volt-Amp: Measure of apparent electrical power usage at a point in time.
kWh	Kilowatt hours: Measure of real electrical power usage per hour.
Low fixed charge regulations	As set out in the Electricity (Low Fixed Price Option for Domestic Consumers) Regulations 2004. These require Electra to make a price option available for domestic consumers who have annual usage less than 8,000kWhs. Prices must be set such that the fixed daily charge does not exceed 15 cents (excl GST) and consumers should be no worse off under this price option at 8,000kWhs relative to other prices.
Power Factor	The ratio of real power (e.g. kWs) to apparent power (e.g. kVA). 0.98 is considered normal on our network.
RCPD	Regional Coincident Peak Demand: Transpower calculates its interconnection charge for each GXP by its relative share of RCPD.
Sub-transmission	A power line that transports or delivers electricity at 33kV on Electra's network.
System Maximum Demand	Aggregate peak demand for the network, being the coincident maximum sum of GXP demand and embedded generation output.

Term	Meaning
Target revenue requirement	The revenue that we estimate needs to be recovered through prices over the pricing year in order to recover Electra's costs of investing in and operating the network.
TOU	Time of Use: Refers to price options that rely on meters that measure consumption by time of use.
Transpower	Transpower New Zealand Limited: The owner and operator of the national electricity transmission network. Transpower delivers electricity from generators to distribution networks and large direct connect consumers around the country.