Electricity Distribution Business Pricing Methodology Effective from 1 May 2018

31 March 2018

Summary of our prices from 1 May 2018

Purpose

This document describes Electra Limited’s approach to setting electricity distribution prices that will apply from 1 May 2018. The revenue we earn from these charges enables us to safely and reliably build, operate and maintain an electricity network to serve electricity customers 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 the use of distributed energy resources (such as solar photovoltaic generation and battery storage) is increasing. 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 customers.

It is important for prices reflect the impacts of distributed energy resources connected to the network in customer premises and how they interact with the network and new management technologies. In the face of these changes we anticipate there will be an adjustment to consumption patterns and investment decisions by both consumers and distribution businesses. Accordingly, there will be adjustments in price options to deliver cost-reflective and service-oriented prices in this environment.

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 price changes to fairly recover the full cost of the network from all customers that use the network.

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 May 2018 continue this evolution

Our prices that apply from 1 May 2018 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 May 2018

Change	Impact on consumers
Continue transfer existing medium consumers on the Time of Use price option to the Standard Time of Use 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.
Reduce the differential between peak and off peak pricing	In recognition that Electras network is largely unconstrained, we have decreased the differential between time of use prices
Prices set to recover our target revenue for the 2017/18 financial year.	Total target revenue has increased by around 5%, which reflects increases in transmission charges, depreciation and return on investment.

The new prices that apply from 1 May 2018 are set out on the following page. We have included the 2017/18 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 May 2018

Table 2: Electra's electricity distribution prices to apply from 1 May 2018

Electricity Network Prices Kapiti Coast and Horowhenua: Effective 1 May 2018

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 May 2018 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
43,900	F	**Fixed Price - General**		All	cents/day	**5.00**	**11.25**	**10.00**	**3.75**	**15.00**	**15.00**
40,090	A	**Uncontrolled (formerly Anytime)**		All	cents/kWh	9.91	9.96	3.42	3.19	13.33	13.15
24,250	M	**Controlled 20 (formerly Managed Saver)**		As required	cents/kWh	2.36	3.58	1.34	1.29	3.70	4.87
2,791	C	**All Inclusive (formerly Combined)(closed)**		As required	cents/kWh	7.79	7.79	2.79	2.60	10.58	10.39
574	N	**Night (formerly Super Thrifty)**		2300-0700	cents/kWh	0.75	1.42	0.25	0.24	1.00	1.66
2,176	B	**Night Boost (formerly Thrifty)**		2300-0700	cents/kWh	0.94	1.78	0.25	0.24	1.19	2.02
				1300-1600	cents/kWh	0.94	1.78	0.25	0.24	1.19	2.02
768	DN	**Day/Night**	Night	2100-0700	cents/kWh	0.90	1.70	0.25	0.24	1.15	1.94
	DD		Day	0700-2100	cents/kWh	10.81	11.24	3.44	3.19	14.25	14.43
450	TN	**Time of Use**	Night	2300-0700	cents/kWh	0.77	1.46	0.25	0.24	1.02	1.70
	TP	**(formerly Triple Saver)**	Peak	0700-1100	cents/kWh	15.38	15.99	3.32	3.32	18.70	19.31
				1700-2100	cents/kWh	15.38	15.99	3.32	3.32	18.70	19.31
	TO		Off peak	1100-1700	cents/kWh	1.56	2.95	1.34	1.29	2.90	4.24
				2100-2300	cents/kWh	1.56	2.95	1.34	1.29	2.90	4.24
450	TF	Fixed Price - Low User Option				5.00	11.25	10.00	3.75	15.00	15.00
352	EX	**Export**		All	cents/kWh	0.00	0.00	0.00	0.00	0.00	0.00
	U	**Street Lighting**		Timetable		7.13	7.13	3.40	3.40	10.53	10.53
	U	**Community Lighting**		Timetable		7.13	7.13	3.40	3.40	10.53	10.53
	CM	**Community Lighting Maintenance Fee**		Each Fitting	cents/day	15.00	15.00	0.00	0.00	15.00	15.00
244	S	**Fixed Price - Standard Option**		All	cents/day	**70.00**	**113.75**	**50.00**	**50.00**	**120.00**	**163.75**
244	SN	**Standard**	Night	2300-0700	cents/kWh	0.70	0.86	0.22	0.21	0.92	1.07
	SP	**(formerly Standard**	Peak	0700-1100	cents/kWh	8.78	8.78	3.02	2.90	11.80	11.68
		Industrial)		1700-2100	cents/kWh	8.78	8.78	3.02	2.90	11.80	11.68
	SO		Off peak	1100-1700	cents/kWh	1.19	1.46	1.15	1.10	2.34	2.56
				2100-2300	cents/kWh	1.19	1.46	1.15	1.10	2.34	2.56

<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.

Content

1. About Electra

1.1 What we do

Over its network, Electra delivers around 404 Gigawatt hours (GWh) of electricity each year from the national grid to approximately 44,450 consumers. The energy we deliver is sold to consumers via retailers licensed to operate on Electra's network.

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

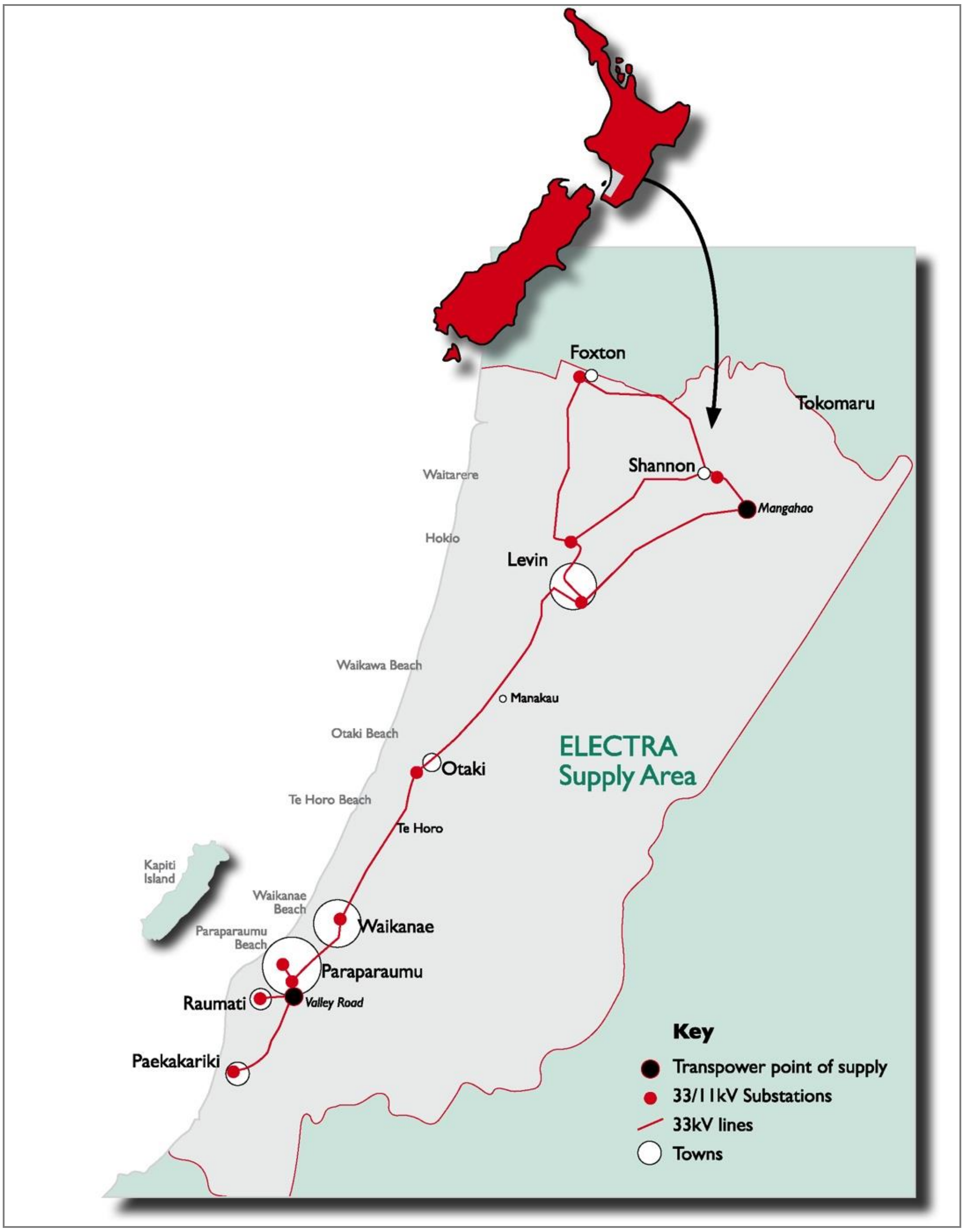


Figure 1: Electra's network supply area

1.2 About our network

We supply a geographic area of around 1700 square kilometres via network concentrated along the coast connecting urban and rural communities, businesses and homes from Paekakariki to Foxton.

We receive electricity at 33 kV from the national grid at two Transpower Grid Exit Points ("GXPs"). Our northern area (Horowhenua) connects to the Mangahao GXP, the southern area (Kapiti) connects to Paraparaumu GXP. While there is no continuous connection between these GXPs, Electra's network accommodates a choice of points for the north-south split and is treated as one network for pricing purposes.

Our 33kV sub-transmission network supplies a series of 33/11kV zone substations located at population centres across the region. From these zone substations, 11kV distribution feeders reach out into the neighbouring communities where electricity is reduced to 400 V through distribution transformers and reticulated throughout neighbourhoods and to rural customers. Almost all consumers are connected to this low voltage network though a very small number of large consumers are supplied at 11kV.

Overlaying the electricity network, Electra's control systems monitor and manage the integrity to the network, assisting our operations and field staff to build maintain and, when necessary conduct emergency work.

Each year in April our Asset Management Plan updates a 10 year forward view of the work we are planning on the network to continue to provide a safe and reliable supply of electricity. This work programme (together with Transpower charges) is a key influence on 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 a cyclic approach and is illustrated in Figure 2.

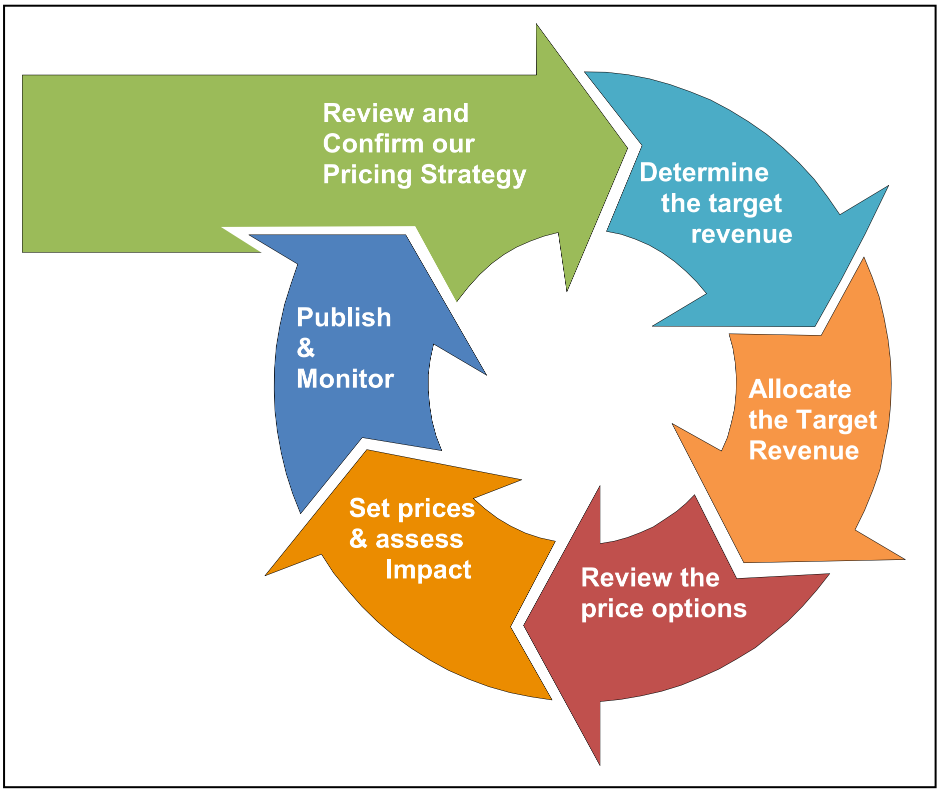


Figure 2: Electra's pricing review cycle

Our pricing review process comprises the following key steps:

- **Reviewing and implementing our pricing strategy:** to guide the evolution of our consumer groups and price options (refer to Section 3);
- **Determine target revenue:** to be recovered through prices (refer to Section 4);
- **Apportion 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 prices 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:** Publish our pricing methodology on our website and monitor the interaction of prices with consumption.

2.2 Customers and Regulation

As a consumer owned distribution business Electra is incentivised to deliver an efficient and reliable service to its consumers. 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 regulated price and quality control, we are subject to regulatory oversight in the form of information disclosure regulation. So in addition to informing our customers of how we set our prices, this document also supports the requirements of the Commerce Commission's Information Disclosure Determination. As part of these requirements, describes 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 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 Context; Electricity use and delivery options will continue to change

Over the past 10 years energy consumption has been declining as improvements in buildings and appliances require less energy to deliver the comforts and conveniences of electricity consumers. This is true internationally as well as throughout New Zealand.

Technological innovation and the adoption of new products for networks and customers will improve reliability, customer service and customer convenience.

Adding complexity, are evolving standards and codes for new types of connections to networks and customer installations such as batteries and Electric Vehicle chargers.

The use of distributed energy resources (such as solar photovoltaic generation and battery storage) is increasing, albeit from a very low base.

The Electricity Authority promotes the provision of cost reflective distribution price options. Electra supports this initiative and together with other Distribution Businesses via the Electricity Networks Association, have been liaising with Retailers to develop common approaches to make cost reflective distribution pricing available and visible to end customers within the overall retail price options.

3.2 Pricing principles

In the above context 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.

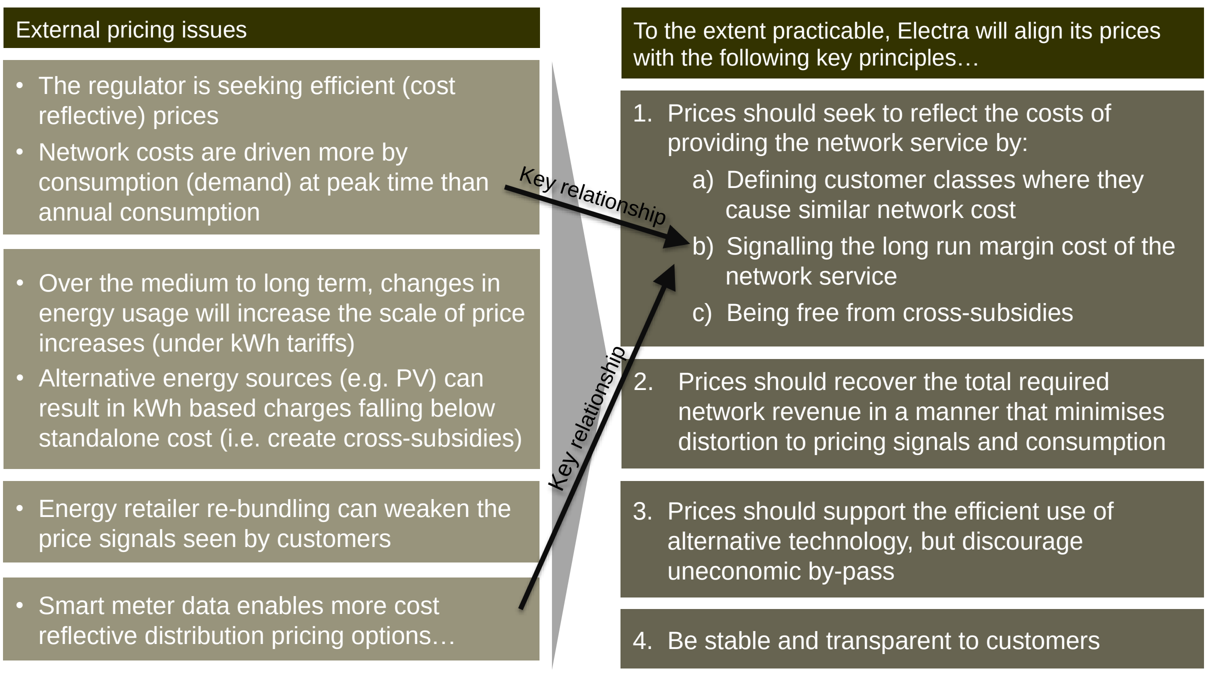


Figure 3: Electra's pricing principles

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

Our distribution pricing strategy flows from the context of change and efficient pricing principles described in the two previous sections. Our strategy is formed 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 distributed energy resources and technologies that deliver improved customer experience.

Balancing these factors will enable Electra to evolve its prices to respond and adjust to anticipated changes in electricity production, exchange and consumption, while continuing to deliver a high level of service to customers within the evolving regulatory framework.

Electra's Pricing Roadmap

Electra will continue to 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 has…

1. Changed to price option naming to align with Electricity Network Association guidelines
2. Implemented a low and medium user time-of-use option.
3. Implemented a low fixed charge daily use charge associated with the time of use option

And will…

4. Consolidate closed price options and consider developing non LUFC / energy bundles, principally for domestic consumers
5. Update the cost of supply model and commensurately adjust the long run marginal cost for the network.

To develop plans to…

6. Improve the attractiveness of time-of-use price options for customers who can shift their peak demand to periods when the grid and generation has greater available capacity
7. Introduce a demand and/or capacity service charge across all customer groups.
8. Continue to transparently explain Electra's service-oriented prices.
9. Accommodate managed distributed energy resources.

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.

3.5 Implications for prices in subsequent years

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

- The adjusted price options developed from a new cost of supply model, which will include an assessment of our long-run marginal cost;
- Improve the attractiveness of time-of-use price options for customers who can shift their peak demand to periods when the grid and generation has greater available capacity;
- 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 2018/19

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.

Our estimate of target revenue for the 2017/18 financial year is set out in Table 3 alongside the 2016/17 target revenue, which is provided for comparison purposes.

Table 3: Target revenue requirement

Component of target revenue	2017/18 Forecast	2018/19 Plan	Change (%) from Forecast
Transmission charges	11.59	10.72	-0.6%
Operating and maintenance	5.26	4.68	-11.0%
Administration and overheads	3.98	4.64	16.6%
Depreciation, Disposal & Interest	9.42	9.50	0.8%
Return on Investment (before tax and discount)	15.90	15.91	0.1%
Distribution Sales Revenue	44.28	43.94	-0.1%
Other Sales	1.86	1.51	-18.8%
Total Revenue	**46.14**	**45.46**	**-1.5%**

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.

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.

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.

Transpowers charges have reduced for 2018/19. Two drivers have contributed to this, the first is a planned reduction of transmission charges at this stage of Transpowers regulatory control period, the other is the effect of a very wet 2017 winter with much more consistent generation from Managahao during regional peak demand, this fortuitous performance results in low charges in the following year.

4.3 Operating and maintenance costs

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 decreased in 2018/19 as a result of one off activities in 2017/18 are not repeated.

4.4 Administration and overheads costs

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 increased materially due to data quality improvement requirements to support greater asset stewardship insights and the ability to more easily service increased disclosure and audit requirements signalled by the Commerce Commission.

4.5 Depreciation

Depreciation reflects the 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, an equivalent amount of capital investment is applied to the network. The extent of these capital projects is shown in our AMP. Depreciation increased over 2017/18 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. Depreciation is planned to be slightly higher in 2018/19.

4.6 Return on investment

Return on investment was better than expected for 2017/18, commensurate with higher than expected revenues. In 2018/19 this is expected to be very similar if operational costs remain contained and revenue targets are met. In 2017/18 a discount of $7.7 M was provided to our consumers.

5. Allocation of target revenue to consumer groups

5.1 Consumer groups

The basis for the consumer groupings we have adopted in our 2018/19 pricing methodology is unchanged from last year. We have three primary consumer groups, with one transitional consumer group:

Table 4: 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 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 unchanged in the current phase of our pricing road map.

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. Surplus revenue not required for the operation and development of the business is used to discount consumer electricity bills.

Consumer feedback

Each year we undertake 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). As we complete this version of the Pricing Methodology, preliminary indications from this year’s survey are: Consumer feedback included:

Table 5: Consumer survey results

% of respondents that	Customer type	2014	2015	2017#	2018#
Provides a reliable electricity supply	Overall	98%	94%	-	-
	Domestic	NS	NS	95%	91%
	Commercial	NS	NS	90%	88%
Fixes fault quickly	Overall	78%	76%	-	-
	Domestic	NS	NS	78%	75%
	Commercial	NS	NS	69%	67%
Has reasonable charges	Overall	44%	46%	-	
	Domestic	NS	NS	44%	43%
	Commercial	NS	NS	42%	40%

* Not Separated, # Conducted early 2018 rather than 2017

Electra experienced a significant wide area outage affecting 13,000 customers across Paraparaumu and Raumati in July 2017. A range of strategic and tactical projects have been initiated to mitigate future occurrence, these will deliver progressive improvements over the next five years. These have absorbed some of the transmission savings and we have been able to keep pressure on the revenue required.

The survey 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 4% of respondents indicating they had installed solar photovoltaic (“PV”) supply and 21% suggesting they were considering it. The installation of PV creates both commercial and operational challenges and opportunities for the network. Accordingly, our new technology focus seeks to integrate smart technology on the network, in homes and businesses, in our operational systems and in our engagement with our consumers.

Table 6: Consumer survey results

% of respondents that	Customer type	2012	2013	2015	2017	2018
Use energy efficient light bulbs	Domestic	78%	84%	86%	85%	89%
	Commercial	54%	61%	69%	70%	73%
Use of a heat pump	Domestic	27%	32%	38%	40%	45%
	Commercial	30%	30%	40%	44%	46%

5.3 Cost drivers

<u>**Overview of network attributes that influence cost drivers**</u>

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 directly associated with investing in, maintaining, and operating the network together with the costs of taking 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 7: Key network attributes

Network attribute	Value
Consumer numbers (no.)	44,450
Total circuit length (km)	2,256
Consumer density (ICPs/km)	20
Zone substation installed firm capacity (MVA)	352
Maximum demand (MW)	104
Energy delivered to ICPs (GWh)	409
Energy density (kWh/ICP)	9,201

Source: 2017/18 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 7 above, Electra's network maximum demand of 104 MW is well below the zone substation installed capacity of 352 MW. This broad measure indicates that the network is not constrained at its key nodes, more specifically forecast constraints at 11 kV distribution and 400 V reticulation 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 comparison to other NZ networks, Electras 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.

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 incrementally increases costs of network operations and planning, fault restoration, and maintenance and general administration. These are reflected in our 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 8: 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.

6. Price options and design

6.1 Price changes

As part of our pricing strategy implementation, we implemented a low fixed charge daily use charge associated with the time of use option, continuing on from the removal of the usage restriction in relation to the Time-of-Use price option introduced last year.

6.2 Price options for 2017/18

Table 9 provides a brief description of each of the price options.

Table 9: Electra's price options

Name	Description	Code	Price component		Unit of measure
Small consumers					
Fixed Price - General	Daily fixed charge applicable to non Time of Use 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					

Name	Description	Code	Price component		Unit of measure
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
Fixed Price - Low User Options	Daily fixed charge applicable to small consumers	TF	n/a		cents/day
<u>Large consumers</u>					
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
<u>Street lighting and Community lighting</u>					
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

6.3 Discussion on price option design

<u>Overall price design elements</u>

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 consumption. As a result, Electra has the lowest average use per connection of all New Zealand electricity distribution businesses (approximately 9,300 kWh per consumer compared to the industry average of more than 16,000 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 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 40,000 kWh to more than 3 GWh). They also have distinct demand behaviours: ranging from flat demand across the standard working day, to variable 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 enable consumers to achieve lower overall cost of supply by moving their consumption to off-peak periods and to offer 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. While we are mindful that retail price bundling may dilute distribution price signals we recognise the customers choice will be influenced by the attractiveness of the retailers overall bundle. In this context we will continue to survey our connected customers, transparently present out price options and work with industry participants to help provide clear cost reflective distribution pricing signals to customers.

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

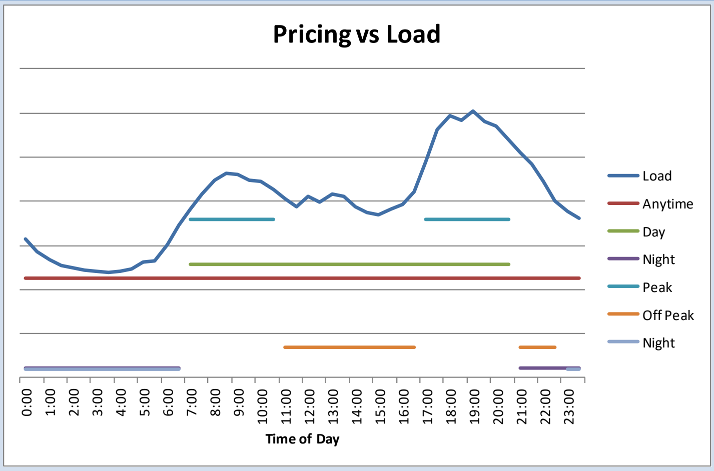
Several of our price options are designed to incentivise efficient use of our existing network capacity by setting higher variable prices at peak periods and lower prices during the shoulders and off peak periods.

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

Figure 5 illustrates our time-of-use price options, usage periods, and how these pricing periods align to our typical daily load profile.

Figure 5: 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). Approximately 90% of consumers have an Uncontrolled connection and these account for approximately 50% of consumption. The Uncontrolled price option recognises that these consumers are able to use the network at any time up to the capacity of their connection.

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.

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 it 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.

6.4 Non-standard pricing

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

6.5 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: https://electra.co.nz/our-company/disclosures/

7. Setting prices for 2018/19

7.1 Changes included in the 2018/19 prices

We have made changes to a number of prices for the 2018/19 period in order to recover the target revenue increase of 1.7% mentioned in Section 4.1. Consistent with our pricing strategy and the Electra Pricing Principles, our general approach was to:

- Distribution price portion; Decrease the differential between peak & off peak and controlled & uncontrolled price options reflecting the generally unconstrained nature of the network. While lower priced off peak and controlled prices have seen a significant percentage increase, this has been strongly moderated by much more modest changes in their partner peak and uncontrolled price options
- Decrease the transmission portion of all prices reflecting a reduction in transmission costs;

7.2 Impact of the changes in prices for 2018/19

Table 10 sets out our prices and the proportion of the target revenue forecast to be recovered from each price option in the 2018/19 pricing year.

Table 10: Summary of changes in prices

Code	Option	Component	Zone On		Existing	New	Change	Estimated Revenue
F	Fixed Price - General		All	cents/day	15.00	15.00	0.0%	$ 2,403,525
A	Uncontrolled		All	cents/kWh	13.33	13.15	-1.4%	$ 27,303,588
M	Controlled 20		As required	cents/kWh	3.70	4.87	31.6%	$ 2,399,738
C	All Inclusive (closed)		As required	cents/kWh	10.58	10.39	-1.8%	$ 1,671,755
N	Night (formerly Super Thrifty)		2300-0700	cents/kWh	1.00	1.66	66.0%	$ 21,483
B	Night Boost (formerly Thrifty)		2300-0700	cents/kWh	1.19	2.02	69.7%	$ 69,078
			1300-1600	cents/kWh	1.19	2.02		
DN	Day/Night	Night	2100-0700	cents/kWh	1.15	1.94	68.7%	$ 82,213
DD		Day	0700-2100	cents/kWh	14.25	14.43	1.3%	$ 943,960
TN	Time of Use	Night	2300-0700	cents/kWh	1.02	1.70	66.7%	$ 163,555
TP	(formerly Triple Saver	Peak	0700-1100	cents/kWh	18.70	19.31	3.3%	$ 3,035,471
			1700-2100	cents/kWh	18.70	19.31		
TO		Off peak	1100-1700	cents/kWh	2.90	4.24	46.2%	$ 673,453
			2100-2300	cents/kWh	2.90	4.24		
TF	Fixed Price - Low User Option				15.00	15.00	New	$ 26,006
EX	Export		All	cents/kWh	0.00	0.00	0.0%	$ -
U	Street Lighting		Timetable		10.53	10.53	0.0%	$ 330,688
U	Community Lighting		Timetable		10.53	10.53	0.0%	$ 37,147
CM	Community Lighting Maintenance Fee		Each Fitting	cents/day	15.00	15.00	0.0%	$ 1,538
S	Fixed Price - Standard Option		All	cents/day	120.00	163.75	36.5%	$ 152,410
SN	Standard	Night	2300-0700	cents/kWh	0.92	1.07	16.3%	$ 205,939
SP	(formerly Standard	Peak	0700-1100	cents/kWh	11.80	11.68	-1.0%	$ 3,031,332
	Industrial)		1700-2100	cents/kWh	11.80	11.68		
SO		Off peak	1100-1700	cents/kWh	2.34	2.56	9.4%	$ 668,769
			2100-2300	cents/kWh	2.34	2.56		

7.3 Sales discount applicable for 2018/19 prices

Electra credits consumers with a discount each year. The sales discount will be credited to the consumer connected to each metered supply point (ICP) on 31 January 2019. The value of the discount is expected to 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 **<u>Incremental Cost</u>** 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. **<u>Standalone cost</u>** 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. **<u>Rural/urban cross-subsidy</u>** 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 principle	**(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;**

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 the Mangahao 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 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.

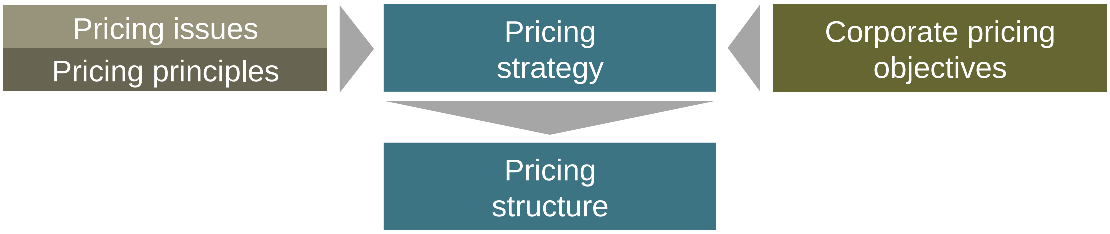


Figure 6: Drivers of the pricing strategy and pricing structure

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 7: 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
2016/17	The year starting 1 April 2016 and ending on 31 March 2017
2017/18	The year starting 1 April 2017 and ending on 31 March 2018.
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 (kW 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 8,000kWh. 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 8,000 kWh relative to other prices.
Power Factor	The ratio of real power (e.g. kW) 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 33 kV 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 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.