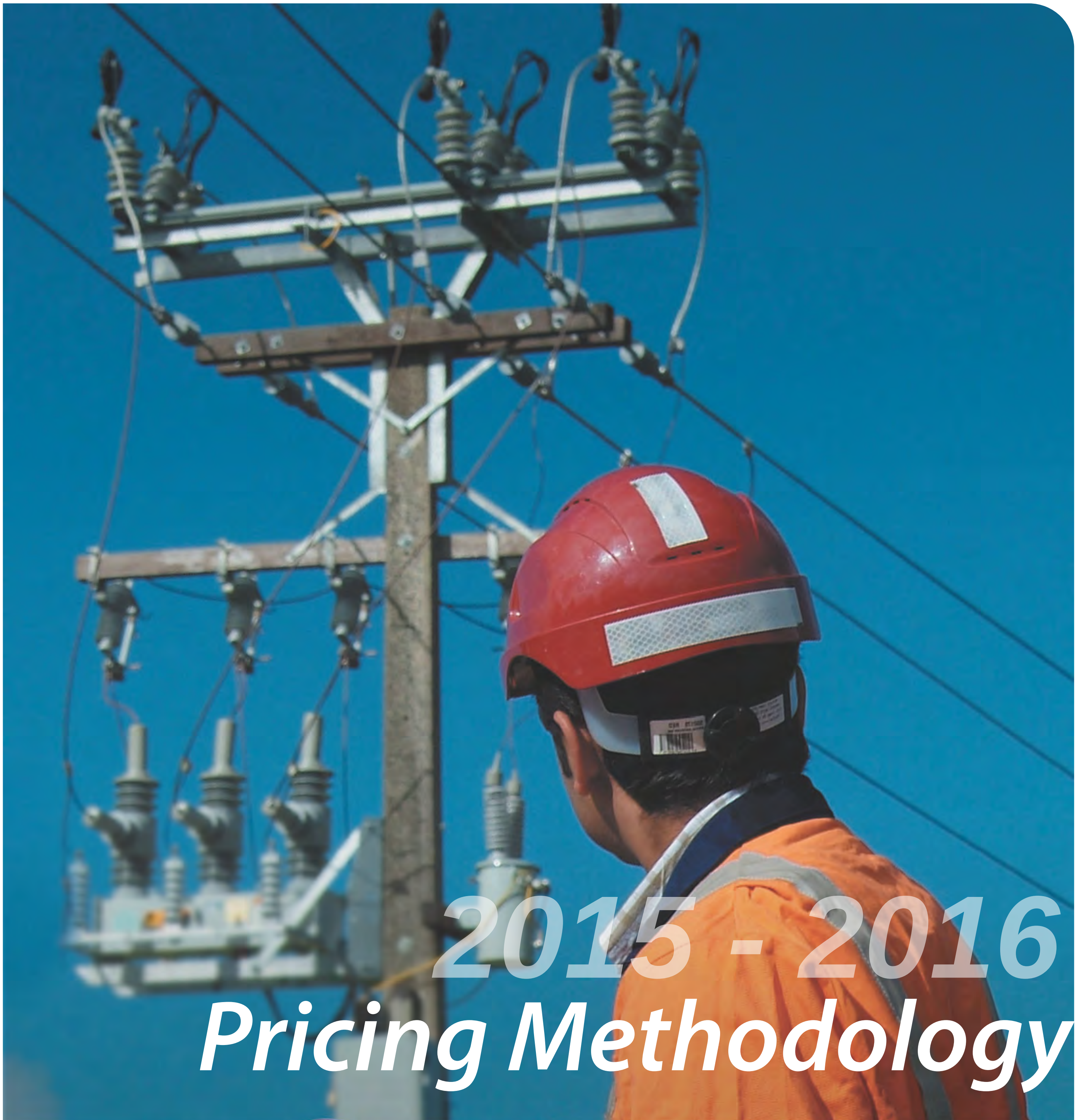
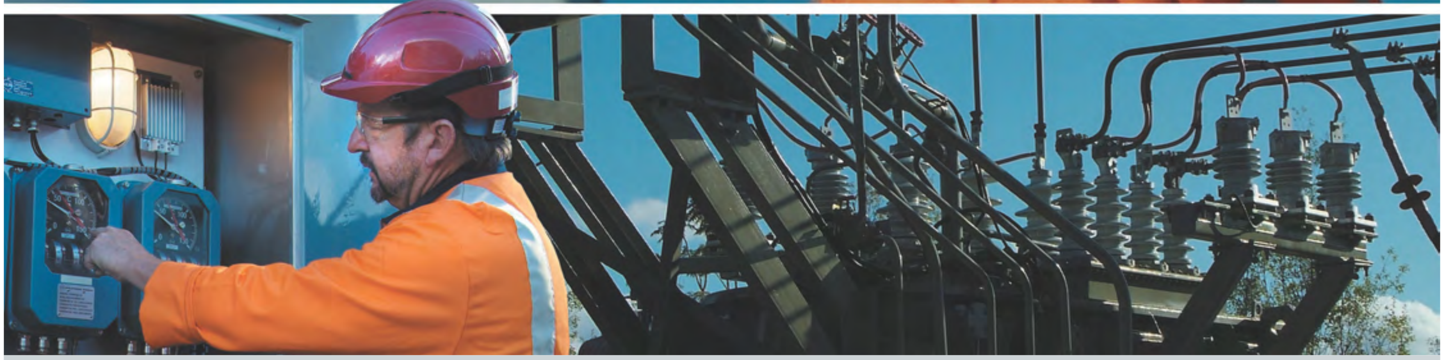


2015 - 2016
Pricing Methodology



For Line Charges, effective 1 April 2015 to 2016

(Pursuant to Electricity Information Disclosure Requirements)

www.topenergy.co.nz

TOP ENERGY®
Te Puna Hihiko

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1. Introduction

Top Energy Limited (Top Energy) is the electricity distribution network in the Mid and Far North of the Northland region. The network distributes some 324,000 kWh of electricity to over 30,668 electricity consumers, who also own the company through the Top Energy Consumer Trust (TECT).

This pricing methodology document describes our key considerations and approach to setting distribution prices effective 1 April 2015. It also sets out our plans and strategy to revise pricing over the next 5 years.

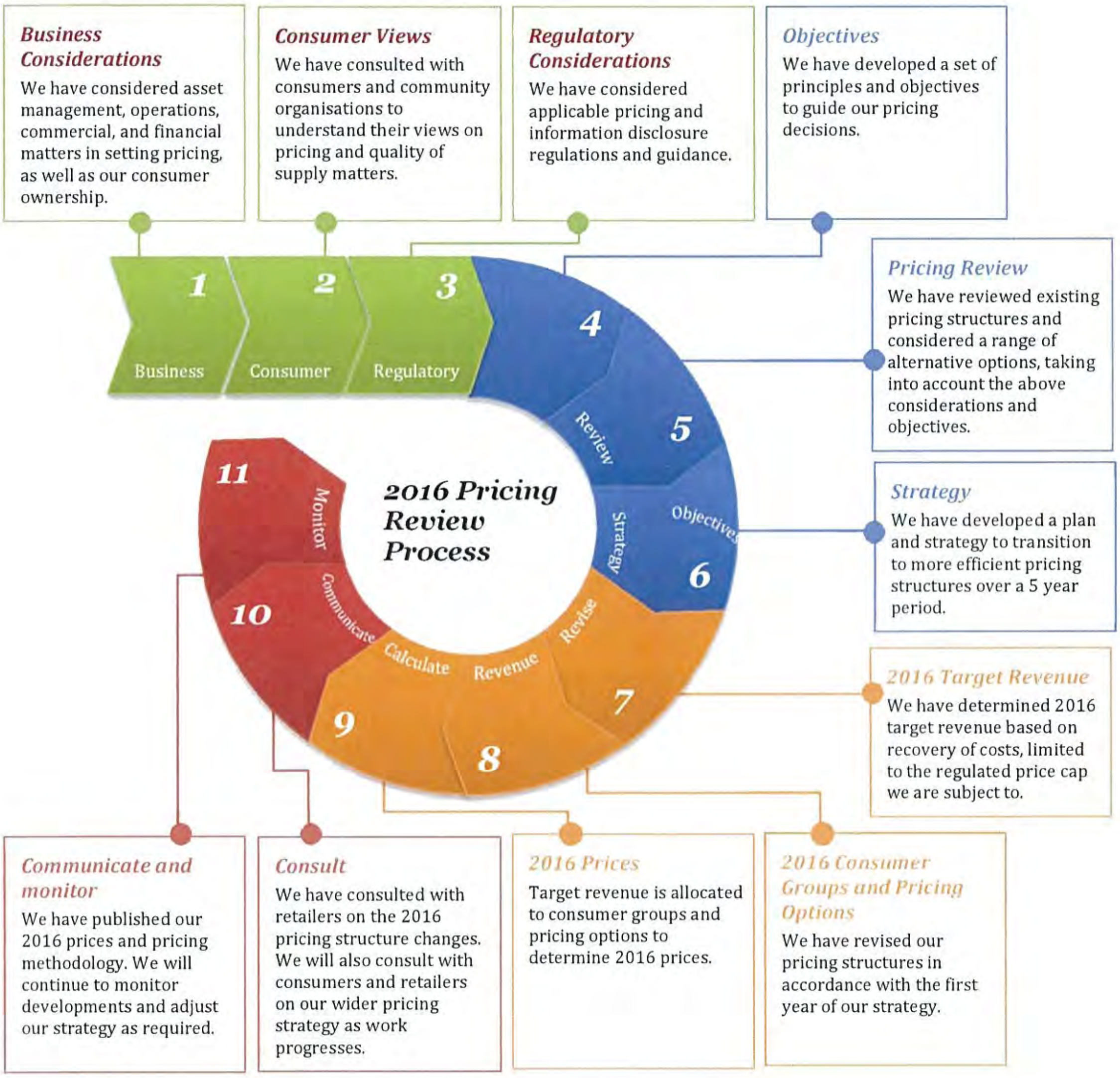
The pricing methodology is structured as follows:

- **Section 2** summarises our approach and key decisions for setting prices in 2015-16
- **Section 3** summarises key considerations we have taken account of in making decisions on pricing
- **Section 4** details our principles and objectives, recent review, and plans and strategy for pricing
- **Section 5 to 7** provides further detail on how prices are set, including:
    - how target revenue is determined
    - key decisions on consumer groups and available pricing options
    - how target revenue is allocated to each consumer and tariff option
- **Appendix 1** provides director certification of this pricing methodology
- **Appendix 2** maps compliance against section 2.4 of the ID Determination
- **Appendix 3** describes how this pricing methodology is consistent with the Electricity Authority's pricing principles published February 2010
- **Appendix 4** provides a glossary of common terms used in this document
- **Appendix 5** details distribution prices that will apply from 1 April 2015

2. Summary of how prices are set

2.1. Process for setting prices

The following diagram illustrates Top Energy's process for reviewing and setting prices in 2015-16.



2.2. How prices are calculated

Prices have been set to recover our 2015-16 target revenue. Target revenue is calculated to recover our forecast costs, but is limited by a price cap determined by the Commerce Commission. Unit prices (comprising a daily fixed charge and/or a consumption-based variable charge) are calculated for each pricing option we offer by allocating target revenue:

- directly to a consumer, where costs are known for specific consumer groups
- using cost allocators for shared costs, which are based on consumer numbers or usage characteristics
- using existing proportions of fixed and variable charges.

Figure 1 illustrates how target revenue is allocated to consumer groups and prices.

Figure 1: Calculation of prices (illustrative)

Notes: UM: Unmetered, IND: Industrial, DG: Distributed Generation

2.3. Key changes to prices in 2015-16

Distribution prices (before any line charge discount is provided) have increased by 2.6% on average in order to recover allowable revenues permitted under price cap regulation. These increases will be recovered through an increase in variable charges for most consumers and from increases in fixed charges for Industrial (IND) and Unmetered (UM) consumers. Appendix 5 provides further detail on how prices will change.

In 2014, Top Energy initiated an in depth review of our pricing approaches. Initial analysis highlighted several areas where the efficiency and effectiveness of our pricing could be improved. We are continuing to analyse and develop pricing options and further detail will be provided at a later date. However, as an initial step we have made several incremental changes to 2015-16 pricing structures. In particular, TOU pricing has been opened up to more consumers with TOU periods being revised to better reflect network demand periods. Several pricing options have been closed to new consumers in anticipation of future changes (ie CAP150, CAP150F, SPECIAL). The usual discount on prices will also no longer be posted alongside prices in order to simplify the pricing schedule. Any future discounts will be announced separately as a discretionary discount.

As a result of the change to the treatment of the discount – moving from being posted to discretionary, the price increase is also measured as the change in the prices disclosed in the tariff schedule. This is measured as the difference between the 2015 price after the posted discount and compared to the 2016 price before the discretionary discount. This increase is 21.0% and is reflective of Top Energy charging significantly below the price path in the last regulatory period. This is a one-off anomaly due to the change from a posted to discretionary discount.

3. Pricing considerations

3.1. Business considerations

Top Energy is the local electricity distribution network in the Mid and Far North of the Northland region. Top Energy's network begins in Hukerenui, approximately 25km north of Whangarei and ends at Te Paki, 20 km south of Cape Reinga. It spans from the East Coast to the West Coast. The supply area is sparsely populated with no dominant urban centre and is recognised as one of the more economically depressed areas of the country.

The company is an integral part of the Far North community. It is owned by its customers through TECT. Consumer trust ownership means that surpluses not required for the operation and development of the network are returned to consumers via sales discounts on electricity bills and through a dividend to TECT. Top Energy also employs more than 200 people and is one of the largest employers in the Far North.

The utilisation of the network is heavily weighted towards small consumers, representing 99% of connections and over 78% of maximum demand. This is evidenced by the fact that average consumption is the second lowest in the country at 10,500 kWh/consumer. Top Energy's pricing structures are therefore strongly focussed on the needs of the mass market, with only a few large connections.

The network receives supply from the national grid at Transpower's Kaikohe substation and from local generation at Ngawha. The Kaikohe substation supplies the southern part of the network directly, with the northern part of the network supplied from a single transmission circuit to Kaitaia. Electricity is then distributed to consumers across long distribution feeders supplied from a limited number of zone substations.

This configuration is a legacy of a network design focused on providing electricity to a sparsely populated, economically deprived area, at a time when cost rather than reliability was the main driver for network development. Over 35% of Top Energy's lines were originally built using subsidies provided by the Rural Electrical Reticulation Council (RERC). This levy assisted post-war farming development in remote areas and enabled the supply of electricity to consumers located in sparsely populated rural areas, which would otherwise have been uneconomic to service.

The original network infrastructure was also developed at a time when Kaikohe and Kaitaia were the dominant urban centres. This is no longer the case, with growth now occurring in the Bay of Islands and Kerikeri as well as the East Coast peninsulas. This is where the existing infrastructure is weakest.

Many existing lines now require extensive rebuilding and refurbishment. Many assets are located in sparsely populated rural areas which are uneconomic in some circumstances. However, Top Energy is required by legislation to maintain supply to consumers that were connected to these lines prior to 1993.

Within this environment, Top Energy has had to invest to meet both growth in new areas, while maintaining an appropriate level of service in existing high-cost network areas. The costs of these investments need to be reflected in prices going forward.

3.2. Consumer views

To inform our decisions in regards to the above investments, in 2009 Top Energy consulted with consumers on our proposed network developments and consumer expectations for prices and the quality of service they receive. This was completed via a telephone survey.

The survey results established that 80% of consumers wished to see network reliability improve. There was overwhelming support from community organisations for the construction of a second 110 kV circuit to secure the electricity supply to the Kaitaia region. Accordingly, we embarked on a programme to improve security of supply in which we will invest around $185 million by 2024; the single largest expansion in the history of the network.

Top Energy completed two surveys in 2014. The first was a customer telephone survey to update our understanding on preferences for quality of supply and pricing. This revealed that:

- 90% of consumers perceive their current supply reliability to be acceptable or better than acceptable
- 90% of consumers believe supply reliability had either stayed the same or improved slightly over the past few years
- Consumer expectations are that:

  - a normal outage should be less than 2 hours
  - an outage caused by an extreme weather event should be less than 26 hours
- There was also a clear preference for planned outages over unplanned.

These views suggest consumers are starting to see the improvements from the first stages of the investment programme and that there is ongoing support for continuing to improve security of supply.

In regards to price, over 80% of respondents:

- do not want to pay more for greater reliability
- believe that rural consumers should pay the same as urban consumers
- believe low users should pay their fair share of the supply costs.

Of particular interest, 30% of those surveyed are considering other energy sources, including solar and bottled gas.

The second survey was an online survey conducted at our stand at the local A&P show. This revealed that:

- 93% of consumers perceive their current supply reliability to be acceptable or better than acceptable
- 60% are considering alternative energy sources

In regards to price:

- 74% of consumers would pay for further reliability improvements
- 70% believe that consumers should pay a fair cost regardless of volume used

These latest surveys have assisted us in our review of our current pricing and future developments.

3.3. Regulatory considerations

Top Energy is subject to regulations which influence our pricing decisions as well provide guidance on how prices should be set. These are summarised in Figure 2.

The Commerce Commission determines and annual cap on lines charge revenue which it considers is sufficient to recovery our reasonable costs, as well as an appropriate return on investment.

We must also publish a range of information on our prices and pricing methods. This pricing methodology is prepared pursuant to these requirements (see Appendix 2).

The Electricity Authority's pricing principles and information disclosure guidelines also provide useful guidance on setting economically efficient prices. We have considered the extent to which our pricing methodology aligns with these principles in Appendix 3.

Figure 2: Summary of relevant regulations

Regulation	How this affects Top Energy's prices
Electricity Distribution Services Default Price-Quality Path Determination 2015 (DPP)	Prices must not exceed allowable revenues determined by the Commerce Commission
Section 2.4 of the Electricity Distribution Information Disclosures Requirements (ID)	Requires Top Energy to publish certain information on prices and pricing methods
Distribution Pricing Principles and Information Disclosure Guidelines (Pricing Principles)	Provides guidance on: • economic principles and market considerations for setting prices • information that should be made available to support pricing methodologies
The Electricity (Low Fixed Charges Tariff Options for Domestic Consumers) Regulations 2004 (LFC Regulations)	Requires Top Energy to offer a tariff option to domestic consumers using less than 8,000kWh per annum that has a fixed daily tariff not exceeding 15 cents.
The Electricity Industry Participation Code, Part 6 - pricing of distributed generation.	Limits prices for distributed generation to the incremental costs of connecting generation to the network, taking into account any avoided costs.
The Electricity Industry participation Code, Part 12A.	Top Energy must consult with retailers in relation to any changes to pricing structures.

4. Pricing Decisions

4.1. Pricing objectives

Top Energy has adopted the following six pricing objectives, informed by the above considerations:

1. Prices provide an adequate return to the shareholder within the restrictions of the Commerce Commission's price control regime.
2. Prices are economically efficient, transparent, and simple to understand, but also recognise the socio-economic needs of consumers and the region
3. Prices reflect a fair and efficient allocation of cost, regardless of actual volumes of electricity consumed
4. Prices provide consumers with opportunities to significantly reduce their charges where they are able to make changes in their usage of the network to reduce Top Energy's long run costs
5. Price stability and certainty is maintained by signaling changes in advance and by transitioning these changes over an appropriate timeframe to avoid price shock
6. Prices do not differentiate urban and rural consumers

These objectives are informed by the key considerations discussed in the previous section, including business considerations, consumer feedback, and regulatory guidance (in particular the Electricity Authority pricing principles).

Trade-off exists across these objectives which must be balanced. Our current focus in meeting these objectives is:

- To allocate costs fairly between consumer groups
- To establish a range of tariff options that reflect consumer requirements
- That tariffs reflect the potential demand and capacity required by consumers
- To comply with regulatory requirements
- To appropriately recover pass through costs
- To achieve a rate of return acceptable to shareholders.

4.2. Pricing review

Recent regulatory initiatives (including the Electricity Authority review of Top Energy's pricing methodology against the pricing principles) and industry developments (e.g. deployment of smart meters, uptake of solar PV) have prompted Top Energy to review its pricing approaches in 2014. PwC was engaged to support this review, by developing a cost of service model (COSM) and looking at more efficient tariff structures. Initial analysis suggested that the pricing methodology could be improved to better reflect economic, regulatory and industry best practice.

Key findings from the COSM analysis were that:

- There was minimal subsidisation between consumers in rural and urban areas under existing prices
- Subsidies were identified between the north and south regions of the network

- Prices for industrial, low users and streetlights under recover the average cost to serve these consumer groups.

Based on this review, Top Energy is now considering moving from consumption based charges towards prices based on demand/capacity-utilisation or time of use. These forms of pricing are facilitated by the roll out of smart meters. and better reflect the service we provide and cost structure (ie capacity in the network). Other pricing improvements being considered include:

- Better alignment of prices with implied cost allocations calculated under the new COSM
- Increasing the proportion of fixed charges to reduce billing volatility (fixed charges currently represent only 8% of revenue)
- Reviewing the current approach to complying with low fixed charge regulations, taking into account any changes arising from the proposed review of these regulations
- Aligning time of use periods to peak demand periods on the network to incentivise more efficient use of existing network capacity
- Progressively closing legacy tariffs.

4.3. Five year pricing strategy

Top Energy has developed a plan and strategy to progress the key findings of our 2014 pricing review and to transition to new pricing structures by 2020. A 5 year timeframe to develop and implement these changes is considered appropriate, factoring in:

- The need to collect and analyse available pricing and billing information
- New consumer insights and pricing applications made available by the roll out of smart meters
- Upcoming pricing guidance expected to be provided through:
  - The Electricity Authority's 2015-16 review of electricity distribution pricing regulations, low user fixed charge regulations, and DG pricing
  - The Electricity Network Association's (ENAs) work stream to review and develop common tariff definitions and solutions. Top Energy is represented on the ENA working group.
- Consultation with consumers and retailers
- Sufficient time to transition tariffs to avoid price shock to individual consumers.

The table below highlights the planned approach to achieve Top Energy's objective of demand/capacity based pricing by 2020.

Figure 3: Top Energy's 5 year pricing strategy

Year 1 (2016)	Year 2 (2017)	Year 3 (2018)	Year 4 (2019)	Year 5 (2020)
COMMENCE	ASSESS	MEASURE	COMMUNICATE	IMPLEMENT
Redefine TOU periods to reflect actual peaks – align with industry	Assess EA changes to LFC regs.	Update COSM	Consult with consumers and retailers on planned changes	Demand or Capacity Based Pricing for all consumer groups "Connection Charge"
Extend TOU option from 30,000 kWh	Review industry changes and align if suitable	Assess data from Smart Meters	Update COSM	Bundled plans
Tidy billing data – review ICP/tariff anomalies	Assess non permanent residence tariff	Review industry changes and align if suitable		

It is difficult to quantify the impact of these changes at this stage. We plan to provide further information on how consumers will be impacted as our review progresses.

5. Target revenue

The first step in the pricing process is to establish the total target revenue to be recovered through prices. Distribution prices are set to generate sufficient revenue for Top Energy to recover its costs, subject to DPP allowable revenues. These costs are discussed in further detail below:

Figure 4: 2015-16 Breakdown of Target Revenue

COMPONENT OF TARGET REVENUE			
	2015-16	2014-15	Change %
Transpower Charges	5,077,526	5,824,018	-12.8
Avoided Cost of Transmission (ACOT) - Transpower	2,018,208	1,833,762	10.1
Avoided Cost of Transmission (ACOT) – DG	2,728,038	2,719,025	0.3
Pass-through Costs	196,888	191,296	2.9
Other recoverable costs	2,132,000	-	
Pass-Through subtotal	**12,152,659**	**10,568,100**	**15.0**
Network Operating Costs	5,587,000	5,550,000	0.7
Non-Network Operating Costs	7,355,699	6,799,512	8.2
Depreciation	8,968,000	6,939,648	29.2
Pre tax return on investment	16,100,880	19,865,549	-19.0
Distribution subtotal	**38,011,579**	**39,154,708**	**-2.9**
Annual Revenue Requirement	**50,164,238**	**49,722,808**	**0.9**
DPP Compliance Adjustment	(3,532,328)	(10,259,005)	-65.6
TOTAL TARGET REVENUE	**46,631,910**	**39,463,804**	**18.2**

The total Target Revenue has increased by 18.2% largely driven by Other Recoverable Costs, being the Claw-back and NPV Allowances from the last regulatory period and higher depreciation charges from the network investment programme.

5.1. Price cap regulation

Top Energy has set total target revenue for 2015-16 at $46.4m to comply with the default price path (DPP) and based on consumption and connections forecasts. The target revenue is before any discretionary line charge discounts that are paid to consumers through a reduction in their electricity bill. Discretionary discounts are forecast to be in the vicinity of $5.1m for the year, representing 11% of target revenue.

Under the 2015 DPP Determination, Top Energy is allowed a price increase of 8.29% in the 2015-16 pricing year and CPI + 7% price increases in subsequent pricing years. This decision was based on an allowable return on investment for the 2016-2020 regulatory period of 7.19% (67th percentile vanilla Weighted Average Cost of Capital (WACC)).

In addition, Top Energy is allowed to recover pass-through and recoverable costs including transmission charges, Avoided Transmission, rates, levies, claw-back and NPV wash-up.

5.2. Transpower charges

Top Energy passes through all transmission charges at cost in accordance with the DPP and its own pricing principles. The transmission charge is equitably distributed across all customers. Transmission charges include:

- Connection Charges – Transpower charges for use of Kaikohe GXP connection assets to which Top Energy's network connects to the national grid
- Interconnection Charges – Transpower charges for use of core grid assets based on Top Energy's share of Regional Coincident Peak Demand (RCPD) in Transpower's Upper North Island demand measurement region
- New investment charges – Transpower contractual charges for grid connection capacity and security upgrades determined by agreement between Transpower and Top Energy.

5.3. Avoided Transmission – Transpower assets

Transmission assets between Kaikohe to Kaitaia sub stations were transferred from Transpower to Top Energy on 1 April, 2012. This resulted in a decrease in Transpower's Connection Charges. A notional avoided connection charge has been incorporated in Top Energy's pricing as a transmission recoverable cost, as allowed under the DPP. This will be recovered through prices for a limited period of 5 years, after which consumers will benefit through lower lines charges. The purpose of this charge is to incentivise transmission spur-line asset transfers where this reduces consumer prices in the long-run.

5.4. Avoided Transmission – Distributed generation

Avoided transmission and voltage support charges may be payable to embedded generators of greater than 1MW output, when suitable terms have been negotiated with Top Energy. Avoided interconnection charges are paid in recognition of a generator's contribution to reducing Top Energy's share of Transpower RCPD peaks.

5.5. Pass-through costs

This includes rates and regulatory levies.

5.6. Other recoverable costs

The DPP allows Top Energy to recover an allowance for the under-recovery of allowable revenues in previous assessment periods (comprising a "Claw-back" and "NPV Wash-Up" allowance). This allowance is $2.132m in 2015-2016.

5.7. Network costs

Network costs comprise mainly maintenance costs. These are derived from the network maintenance programme which provides consumers with acceptable levels of safety and reliability, including an allowance for repairs following faults. The amount is determined in conjunction with Top Energy's Asset Management Plan.

5.8. Non-Network costs

These are costs incurred in managing the day to day operations of the business, including management, finance and administration costs, as well as system operations and network support.

5.9. Depreciation

Depreciation represents the return of Top Energy's asset investment and is estimated using 2014 Regulatory Asset Base (RAB) roll-forward.

5.10. Pre-Tax WACC

A pre tax return on investment is derived by applying a pre-tax weighed average cost (WACC) to Top Energy's regulatory asset base (RAB). Our 2016 WACC estimate of 8.76% is based on the DPP WACC (7.19%) expressed on a pre-tax basis.

5.11. DPP compliance adjustment

This represents an adjustment to our breakdown of costs to ensure compliance with allowable revenues under the DPP. In the 2015-16 year, the adjustment is negative as Top Energy is charging below what is required to achieve the allowable return on the investment in the network. This has occurred as Top Energy's price path is smoothed under the DPP to prevent any potential price shocks to consumers.

6. Consumer Groups and Pricing Options

6.1. Cost drivers

We have sought to align our consumer groups and pricing options to reflect differences in the key drivers of our costs. Approximately, 85% of our costs are associated with directly investing in, maintaining and operating the network, as well as receiving supply from Transpower. The remaining 15% is associated with general management and administration of the business. Top Energy considers that our network cost drivers are:

- peak demand
- the length of circuit required to supply consumers
- the number of consumer connections
- dedicated asset costs.

The cost drivers that are relevant to Top Energy's current pricing methodology are peak demand, the number of connections, and dedicated asset costs, as discussed below.

Peak demand

Top Energy builds capacity in the network to meet forecast demand. As demand increases, Top Energy must consider further investments in capacity. Consumers' peak usage of existing network capacity is therefore a key driver of future costs. For instance, the network faces capacity constraints in a number of growth areas (as identified above) and Top Energy has undertaken a large investment programme in these areas to meet forecast demand.

Circuit length

The distance between a consumer's premises and the point of supply to the network influences the length of lines and cables required to deliver electricity to consumers. Effectively, consumers that are further away from the Kaikohe GXP create relatively higher costs for Top Energy.

In our view, it is not practical, or necessarily fair, to distinguish individual consumers by circuit length. However, groups of consumers within network sub-regions can be distinguished. Recently we investigated the merits of adopting pricing sub-regions, reflecting rural and urban and Northern and Southern network supply areas, respectively. While some cost differences were evident across these regions, potentially justifying different prices, consumers have sent a clear message that rural consumers should pay no more than urban areas. For similar reasons, we have decided not to distinguish between the Southern and Northern networks.

Therefore, while circuit length is a relevant cost driver, Top Energy has decided not to reflect this in pricing other than for Industrial customers.

Consumer connections

New connections create investment and ongoing operations and maintenance costs. Top Energy's policy is for consumers to contribute towards capital costs in an upfront capital contribution. Remaining connection related costs must therefore be recovered through pricing.

Consumer specific costs

As a general principle, costs that are specific to individual consumers or groups of consumers should be directly recovered from these consumers, where practical. The provision of street-lighting and community lighting is an example of a cost that is only caused by a specific group. Transmission and assets costs for large industrial consumers can also be identified and prices set to reflect these costs through non-standard contracts.

Pricing distinctions could also be made based on network regions (discussed above), use of the high voltage network only, and use of dedicated transformers. However, our review of pricing suggests there is little benefit for Top Energy in disaggregating prices to reflect these costs.

6.2. Consumer Groupings

Prices are disaggregated into four consumer groups, which reflect the use of assets, connection profiles, and contribution to maximum demand, consistent with key network cost drivers:

Figure 5: Consumer Groups

Consumer Group	Criteria	Rationale	Pricing and commercial terms
Industrial (IND)	Industrial loads consuming >3,000MWh per annum, with >1MVA installed capacity	Distinguished due to much larger load size and given Transpower and Top Energy's distribution costs can be identified for each consumer.	Non-Standard
Large Scale DG (DG)	Distributed Generation connections greater than 1MW output	A Connection charge to recognise the Network assets utilised to connect the DG into the distribution system.	Non-Standard
Time of Use (TOU)	Large commercial and domestic loads consuming between 30MWh-3,000MWh per annum with TOU metering	Pricing incentivises the efficient use of network capacity by large loads through a variable charges levied on peak, shoulder and off-peak time of use periods.	Standard

Non Time of Use (NTOU)	Small commercial and domestic loads without TOU metering	Recognises the large majority of small load connections without access to time of use meters. This group will eventually become a mass-market group as the non-TOU CAP150 tariff is now closed and all large consumers will eventually move to TOU tariffs.	Standard
Unmetered (UM)	Street and community lighting and other unmetered connections	This group recognises the unique cost and network usage profile of street and community lighting.	Standard

6.3. Summary of pricing options

Top Energy offer the following pricing options within the above consumer groups.

Figure 6: Tariff Options

Price Code	Consumer Group	Description and rationale	MWh	ICPs
Industrial (IND)	IND	Fixed charge recovery of costs associated with industrial loads consuming >3,000MWh per annum and >1MVA installed capacity.	61,090	3
Large Scale DG (DG)	LDG	Fixed charge recovery of costs associated with the connection of large scale distributed generation into the distribution network.		1
Time of Use (TOU)	TOU	Default tariff for all customers with an annual consumption exceeding 30,000kWh but less than 3,000,000kWh. Total charges for this plan include a fixed charge for each day connected (TOUF) and a variable consumption charge (TOUV) based on kWh consumption during three pricing periods, representing peak, shoulder and off-peak demand periods, as follows: • Peak: 07:30-9:30 and 17:30-20:00 • Shoulder: 07:00-07:30, 09:30-17:30 and 20:00-23:00 • Off-peak: 23:00-07:00	34,210	61

CAP150 (CLOSED)	NTOU	For customers on CT Metering, with a capacity of greater than 100 Amps per phase. Total charges for this plan include a fixed rate for each day connected (CAP150F) and a variable consumption charge (CAP150V) on all loads. This plan is closed to new consumers from 1 April 2015 with existing consumers transitioned to other pricing options over the year.	14,544	132
Day/Night (DAYNGT)	NTOU	Total charges for this plan include a fixed rate for each day connected (DAYF) and two variable consumption charges during a day and night period. The higher day rate (DAYV) applies from 7 am to 11 pm. A lower night rate (NGTV) applies from 11 pm to 7 am to encourage consumers to shift their consumption from the peak day-period. To qualify for this plan consumers must offer at least 3kW of load controllable by Top Energy for up to 6 hrs per day.	15,999	914
Uncontrolled (UC)	NTOU	Total charges for this plan include a fixed rate for each day connected (UCF) and a variable consumption charge (UCV). Variable prices are set higher than other NTOU tariffs to incentivise consumers to take up controlled or DAYNGT tariffs.	62,323	7,304
Partially Controllable (PC)	NTOU	Top Energy can control the Partially Controllable Load for up to 6 hrs per day. The load offered must be at least 3 kW (e.g. a hot water cylinder). Total charges for this plan include a fixed rate for each day connected (PCF) and a variable consumption charge (PCV). Prices are lower than the UC tariff to encourage consumers to offer interruptible load. This assists Top Energy in controlling peak demand during interruptions to supply.	128,858	20,991
Fully Controllable (FC)	NTOU	Top Energy can control the Fully Controllable Load for up to 4 hrs per day and the load offered must be at least 10 kW. Total charges for this plan include a fixed rate for each day connected (FCF) and a variable consumption charge (FCV). Prices are lower than under the UC and PC price options to encourage consumers to offer up large interruptible loads. This assists Top Energy in controlling peak demand during interruptions to supply.	5,320	1,105
Special (CLOSED]	NTOU	Historical Special Meter Configurations		72
UM	UM	11 different tariffs targeted at a range of unmetered supply configurations including: • 9 different street and community lighting configurations • Continuous supply equipment less than 500watts (eg. Battery Chargers, Electric Fences, Irrigation, PCM Cabinets, Phone Booths, Radio Repeaters, TV Boosters) • Intermittent supply equipment (Fire Sirens, Railway Crossing Lights, Traffic Counters). Prices are wholly fixed given these connections are not metered.	1,436	220

6.4. Industrial (Non-Standard)

Industrial pricing aims to recover Top Energy's costs to service these consumers. To meet these consumers' requirements, Top Energy charge a wholly fixed annual tariff divided into twelve equal payments. There is no variable component. This fixed charge comprises the following individual charge items:

- Transpower Connection charges
- Transpower Interconnection Charges
- Avoided transmission charges payable to embedded generators
- Top Energy connection and interconnection charges for its sub-transmission assets
- Top Energy operations and maintenance charges

The charges have been calculated consistent with network cost drivers on the basis of:

- Asset usage (eg no low voltage or distribution level costs are assigned to these consumers as they connect directly into the sub-transmission system)
- Coincident peak demand (ie to directly allocate Transpower charges)

Top Energy does not have additional obligations or responsibilities regarding interruptions to supply for non-standard connections beyond those incorporated in its standard contracts. While additional circuit redundancy and specialist equipment is provided to these consumers in some circumstances, which is sometimes beyond what is provided to many standard connections, these consumers pay for this enhanced level of security on a cost recovery basis.

6.5. TOU

A fixed and variable component is charged to TOU tariffs.

Fixed charges for commercial customers have been set to maintain historical linkages, reduce stranding risk associated with larger connections, as well as reflect the proportion of asset used compared to other pricing options.

Variable rates are set relatively higher during periods of peak demand and progressively lower during shoulder and off-peak demand periods. These time periods have been designed:

- To align with typical demand periods on the network
- To incentivise consumers to shift demand from peak periods to shoulder periods and from shoulder to off-peak periods
- To maintain consistency with industry standard TOU periods
- To maintain consistency with the NGT/DAY pricing periods.

6.6. Non-TOU

A daily fixed charge is levied on all NTOU tariffs, as follows:

- a 15 cent per day is applied to all mass market consumers (except CAP15) to comply with the low user fixed charge regulations
- CAP150 (closed): A higher fixed charge is set for these commercial customers to reflect a higher average levels of consumption and demand

A base line variable tariff is charged to all uncontrolled consumers (UC). Discounts to this standard tariff are applied to DAYNGT, recognising their contribution to reducing peak demand, and PC and FC, to incentivise consumers to offer up controllable load.

6.7. Unmetered

Unmetered pricing is wholly fixed. Fixed charges have historically been set with reference to historical amounts and rolled forward by inflation. However, recent costing analysis suggests unmetered prices are not recovering the cost of supplying these connections. Top Energy will investigate this further over its 5 year pricing strategy horizon.

6.8. Distributed generation

Under Part 6 of the Electricity Industry Participation Code, Top Energy must price distributed generation at no more than the incremental cost of connecting this generation, taking into account any avoided costs.

Top Energy has not developed separate charges for distributed generation, other than for negotiated avoided transmission and voltage support payments to large scale generators (greater than 1MW output). These generators are able to demonstrate on an annual basis that they are making a material contribution towards Top Energy avoiding additional transmission costs.

Large scale distributed generation (>1MW)

Connection charges have been set to recover the costs through a non standard contract.

Avoided interconnection charges may be paid to generators that are connected to the Top Energy's network and which have actively contributed to reducing Top Energy's contribution to RCPD peaks, used to set Transpower's interconnection charges. Avoided transmission and voltage support charges are calculated based on the notified Transpower charges for the applicable pricing period. This requires appropriate metering facilities at each site, so that the contribution to RCPD or voltage support charge reductions can be verified.

In the event that there is more than one eligible embedded generator providing a contribution to lowering the RCPD, avoided transmission charges are calculated based upon the pro-rata value of the metered contribution from each generator at the times of the RCPD peaks.

Other distributed generation

Top Energy considers that other distributed generation customers (eg small scale solar PV) already receive a significant benefit through reduced distribution consumption charges, to the extent that electricity generated on site reduces the amount of electricity delivered via the network. Conversely, the cost to Top Energy of servicing these connections (i.e. an average domestic connection) is not reduced by the presence of the distributed generation, especially if the connection requires access to the network at times of peak demand. Accordingly, we believe that some connections with distributed generation are paying less than the incremental cost of providing the connection to that consumer.

While there are only a small number of distributed generation connections on the network, the planned move to demand / capacity pricing and a higher proportion of fixed charges will ensure that consumers with distributed generation pay a fair share of costs, to satisfy cost recovery and fairness considerations under Top Energy pricing objectives.

6.9. Discounts

Top Energy will remove the posted discount from line charges in 2015-16 to simplify pricing schedules. Any future discount will be treated as a discretionary discount. It is our intention to maintain the same consumption based methodology that has previously been used for posted discounts. Discounts calculated on this basis represent approximately $5.1m.

6.10. Capital contributions

A customer may be required to make an upfront contribution to the cost of extending or upgrading the network (eg arising from connecting to the network). This contribution pre-funds Top Energy's investment, with these costs excluded from line charges.

The value of the Capital Contribution is calculated from the total cost of extension work and reduced by the value of the Top Energy connection subsidy. The contribution represents the uneconomic cost of constructing the line, but does not grant any ownership rights; Top Energy retaining ownership, and responsibility for repairs and refurbishment of the reticulated extension.

Capital Contributions may be non-refundable or refundable depending on the circumstances. Standard charges and requirements apply to typical connection configurations.

The full details of the methodology for determining capital contributions is publically disclosed on the website www.topenergy.co.nz/network/network-disclosures/

7. Calculation of Tariffs

Tariffs are calculated by allocating costs to consumer groups and prices, based on assumed splits between fixed and variable tariffs. Figure 7 summarises the allocators used to allocate target revenue and the rationale for these decisions.

Figure 7: Summary of cost allocators used to set prices

Cost Category	Allocator used	Rationale
Transmission costs (including ACOT - Transmission)	*Interconnection charges and ACOT - DG:* Coincident share of RCPD (kW) for industrial consumers and Anytime Maximum Demand (AMD) for other connections *Connection charges and ACOT - Transmission:* Share of AMD	Allocation of interconnection charges aligns with Transpower's use of RCPD to apportion charges at a national level. Connection charges represent investment in GXP capacity. AMD broadly represents usage of this capacity.
Network Costs	Customer group demand on the system as a percentage of ORC	Spreads maintenance cost in portion to demand, weighted by the replacement cost of assets (recognising higher maintenance is usually attributed to higher cost assets).
Non-Network Costs	Regulatory Asset Base (RAB)	Spreads costs that are relatively static with the size of a customer.
Depreciation	IND: Demand (kW) TOU: RAB NTOU/UM: kWh volume	Allocation based on utilisation of asset utilisation, which broadly corresponds with depreciation representing use of capital.
Pre tax ROI	RAB	Allocates return in proportion to value of assets ODV/RAB, consistent with regulatory framework.

The above allocation approach results in the following allocations of target revenue to consumer groups.

Figure 8: Cost allocation results

					Distribution $'000's						
Consumer Group	Regulatory Asset Base 2013($m)	Number of ICPs	Energy Consumption Forecast 2016 (MWh)	Transmission, Other Pass-through and Recoverable Costs	Network Costs (Maintenance)	Non-Network Costs (Overheads)	Depreciation	Pre tax WACC	Annual Revenue Requirement	DPP compliance Adjustment	Total Target Revenue
IND	4.3	3	61,089,927	1,260	131	172	210	377	2,149	(404)	1,745
TOU	16.4	61	34,209,776	1,355	499	656	800	1,437	4,747	(1,286)	3,461
Unmetered	1.5	216	1,435,665	-	46	60	73	131	310	98	408
LDG	0.7	1	-	-	20	27	33	59	139	(74)	64
NTOU	160.9	30,635	227,043,942	9,538	4,892	6,440	7,852	14,097	42,820	(1,872)	40,948
Total				-							
	183.8	30,916	323,779,310	12,153	5,587	7,356	8,968	16,101	50,164	(3,538)	46,627

Appendix 3 summarises the resulting tariffs.

Appendix 1 – Certification for Year Beginning Disclosures

TOP ENERGY®
Te Puna Hihiko

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Paul Anthony Byrnes and Gregory Mark Steed, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

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

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

P A Byrnes

G M Steed

31 March 2015

Appendix 2 - Glossary

ACOT	Avoided Cost of Transmission
AMD	Anytime Maximum Demand, which is defined as the average of the 12 highest off-take quantities for the customer at the connection location during the Capacity Measurement Period.
CAP150	CAP150 tariff
Capacity Measurement Period	12-month period starting 1 September and ending 31 August inclusive, immediately prior to the commencement of the pricing year.
Consumer	A purchaser of electricity from the Retailer where the electricity is delivered via the distribution network and is interchangeable with customer.
Consumption Data	Data provided by the Retailer to the Distributor as required under the Use of System Agreement, showing details of the measured electricity consumption on the distribution network.
Demand	The rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).
Distributor	Top Energy as the operator and owner of the distribution network.
Code	The Electricity Industry Participation Code 2010
Distributed Generation (DG)	Electricity generation that is connected and distributed within the distribution network, the electricity generation being such that it can be used to avoid or reduce transmission demand costs.
FC	Fully Controllable
GXP	Grid Exit Point, a point of connection between Transpower's transmission system and Top Energy's distribution network.
GST	Goods and Services Tax as defined in the Goods and Services Tax Act 1985.
HV	High Voltage, voltage above 1,000 volts.
ICP	Installation Control Point. Point of Connection on the Distributor's network, which the Distributor nominates as the point at which a Retailer is deemed to supply electricity to a Consumer.
IND	Industrial Customer defined by Top Energy.
Line Charges	The charges levied by Top Energy on Consumers for the use of the Network as described in this Pricing Methodology.
Load Control Equipment	The equipment (which may include, but is not limited to, ripple receivers and relays) which is from time to time installed in a consumer's premises for the purpose of receiving load management service signals.

LV	Low voltage. Voltage up to 1,000 volts, generally 230 or 400 volts for supply to most Consumers.
NToU	Non Time of Use Customer, whose usage is metered using a standard whole current type meter.
PC	Partially Controllable
Pricing Year	12-month period from 1 April to 31 March the following year.
RPDP	Regional Peak Demand Period, relates to an Upper North Island defined by Transpower where Top Energy is located. The half hour in which any of the 12 highest regional demands occurs during the capacity measurement period for the relevant pricing year.
RCPD	Regional Coincident Peak Demand, relates to the customer's off-take at the connection location during a regional peak demand period.
Retailer	The supplier of electricity to Consumers with installations connected to the distribution network.
ToU	Time of Use Customer, who is metered according to their electricity consumption for a particular period (usually half-hourly).
Transpower	Transpower (NZ) Limited.
UC	Uncontrolled

Appendix 3 – Compliance with ID determination

ID Clause	Information Disclosure requirement	Pricing Methodology Reference
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	This Pricing Methodology will be published on our website prior to 1 April 2014.
2.4.1(1)	Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See below for document references to compliance against clause 2.4.3.
2.4.1(2)	Describes any changes in prices and target revenues;	Prices have increased for all customers by an average of 3.8% (pre discounts) and 22.6% when comparing 2015 and 2016 pricing schedules. See section 2.3 Changes in target revenues are described in Section 5.
2.4.1(3)	Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	See section 6.4 and 6.8
2.4.1(4)	Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Public consultation was completed during 2014 (see section 3.2)

2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	Any changes will be disclosed on 1 March 2015.
2.4.3	Every disclosure under clause 2.4.1 above must-	
2.4.3(1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Top Energy considers this document provides sufficient information on how prices have been set but will continually review for improvements.
2.4.3(2)	Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	See Appendix 4 TEL considers our pricing is broadly consistent with the pricing principles but we also discuss how potential changes to our pricing methodology will align more closely with these principles.
2.4.3(3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See section 5.
2.4.3(4)	Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	See section 5.

2.4.3(5)	State the consumer groups for whom prices have been set, and describe- • the rationale for grouping consumers in this way; • the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	See Section 6.2.
2.4.3(6)	If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	See section 2.3 and Appendix 5
2.4.3(7)	Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	See tables in Section 7.
2.4.3(8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See tables in Section 7.
2.4.4	Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
2.4.4(1)	Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Our pricing strategy is discussed in section 4.3
2.4.4(2)	Explain how and why prices for each consumer group are expected to change as a result	See section 4.3
2.4.5	Every disclosure under clause 2.4.1 above must-	

2.4.5(1) (a), (b), (c)	Describe the approach to setting prices for non-standard contracts, including- • the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts; • how the EDB determines whether to use a non-standard contract, including any criteria used; • any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	See Section 6.4 and appendix 5
2.4.5(2)	Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain- • the extent of the differences in the relevant terms between standard contracts and non-standard contracts; • any implications of this approach for determining prices for consumers subject to non-standard contracts;	See Section 6.4

2.4.5(3)	Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- • prices; and • value, structure and rationale for any payments to the owner of the distributed generation.	See Section 6.8
2.9.1	Where an EDB is required to publicly disclose any information under clause 2.4.1, clause 2.6.1 and sub-clauses 2.6.3(4) and 2.6.5(3), the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Completed and attached as Appendix 1

Appendix 4 – EA Pricing Principles

Pricing principles	Extent to which pricing methodology is consistent with 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	We interpret 'incremental cost' as the additional cost of connecting a consumer, comprising connection costs, network upgrades, and incremental operating costs. Top Energy requires a capital contribution for new connections and asset upgrades if the expected line charge revenue from the connection is less than the associated incremental capital cost (i.e. an uneconomic connection). Accordingly, distribution prices will typically be in addition to incremental capital costs. Remaining incremental operating costs resulting from a new connection will be recovered through distribution prices. Over the last ten years a new connection has contributed approximately $300 per annum (real) to operating expenditure. A uncontrolled consumer (UC) would need to consume less than 1,150kWh in a year for prices to fall below this incremental cost (i.e. based on the 15 cent per day fixed charge and existing UC prices). This highlights that the application of the 15 cent per day low fixed charge creates cross-subsidisation at very low levels of consumption. Top Energy considers 'stand alone cost' means the cost for a consumer to disconnect from the distribution network and install onsite generation. Solutions do exist for small loads to disconnect from the network through installation of onsite solar generation and batteries. However, these systems are relative expensive when

	compared to distribution supply. For example, a small 8kWh/day system can cost in excess of $50,000 to install. We estimate this would cost $1.82/kWh in ideal circumstances, assuming the full 8kWh is generated each day over a 15 year period and the installation is funding by a mortgage. This is significantly more expensive than the average 35c/kWh charge Top Energy's consumers pay (source: MBIE quarterly survey of electricity prices, August 14). Nevertheless, the cost of installing these systems is falling rapidly and Top Energy will continue to keep a watch on this market and respond appropriately through pricing.
(ii) having regard, to the extent practicable, to the level of available service capacity	Top Energy's primary service is to provide capacity in the distribution network. We are currently considering the adoption of demand/capacity and TOU based tariffs for all consumers facilitated through smart meters. This will align pricing more closely with the level of available service capacity. Nevertheless, current pricing structures do recognise available service capacity in the network as follows: • Consumer groups recognise different load sizes • Many network and transmission related costs are allocated to consumer groups in proportion to demand • Capital contributions help fund the uneconomic proportion of new investments in capacity • Consumption based tariffs provide a broad incentive to reduce consumption • Industrial sites (IND) are charged for specific asset usage and therefore the capacity these assets provide, and are apportioned transmission charges directly based on their contribution to RCPD • TOU and DAYNGT tariff structures encourage consumers to shift load outside peak usage periods • Controlled tariffs encourage consumers to offer up controllable load which Top Energy can use to manage congestion during interruptions to supply, when the network maybe constrained

(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs	For the same reasons discussed above, Top Energy's pricing structures signal the cost of investing in additional network capacity. Top Energy's plans to move to demand/capacity or TOU pricing will improve these signals.
(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	This principle suggests that consumers with a higher willingness to pay should pay relatively more than consumers with a lower willingness to pay. Top Energy considers pricing based on willingness to pay should be linked to the level of service provided. This is a common pricing practice in many competitive markets. For instance, the UC and PC/FC pricing options give consumers a choice over whether heating loads are interrupted. Consumers that are unwilling to have supply interrupted pay relatively more than a customer that is willing to accept a slightly lower level of service. Similarly, consumers on DAYNGT and TOU pricing options that do not want to shift load to off peak periods pay more for using electricity at time that suits them.
(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	Top Energy is not aware of any disconnections arising from uneconomic bypass of its network. Small scale DG (eg solar connections on houses) creates a risk of uneconomic bypass that is detrimental to Top Energy. However, as discussed, we consider it is currently uneconomic for a consumer to disconnect from the network in this manner. However, in many cases these connections demand power at peak times, however, contribute very little at non-peak times. Connections with small scale DG therefore contribute little to fixed costs of connecting them to the network. A move towards capacity/demand/TOU pricing and a higher proportion of fixed charges will address this

	issue. Another potential area of uneconomic bypass is where large loads are situated close to a Transpower GXP and could bypass Top Energy's network to connect directly to the Grid. Only one large industrial load (based in Kaitaia) would be of a size sufficient to connect to Transpower's network. It would be uneconomic for this consumer to connect to the nearest GXP at Kaikohe.
(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	Capital contributions and non-standard contracts provide a mechanism where a consumer can request assets that provide a higher level of service. The costs of specific assets are either recovered upfront through a capital contribution or within pricing. Consumers can also request alternative pricing structures under non-standard contracts to address their own risks (eg IND tariffs are wholly fixed).
(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives and technology innovation	Avoided transmission and voltage support charges may be payable to embedded generators of greater than 1MW output. This helps to justify investments in local generation (eg at Ngawha).
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact to stakeholders	The pricing strategy explained in this document provides stakeholders with an overview of Top Energy's plans for prices over the next 5 years. We plan to consult with consumers and retailers to seek their feedback on any changes which will be incorporated into any pricing decisions. Any changes will be transitioned over a reasonable period to avoid price shock to consumers. This 5 year period aligns with the 5 year regulatory period set by the Commerce Commission which will also provide consumers with certainty and transparency over total allowable revenues.

(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	The same tariff structures apply to all retailers supplying consumers on Top Energy's network. We do not consider our pricing structures provide an advantage to any individual retailer. The new TOU time periods have been established after considering standard practices used by other distributors to minimise transaction costs for retailers. Future tariff innovation will reference to standard distribution sector pricing solutions developed by the ENA. Transmission and distribution charges are bundled for all consumers except large industrials.

Appendix 5 - Network Line Charges 2015 – 2016

DISCLOSURE OF ELECTRIC LINE CHARGES

Effective from 1st April 2015

All prices exclude $GST

Top Energy is required by law to disclose details of line charges.

1. Standard tariff charges comprise a fixed network charge and a variable charge based on units distributed
2. Each ICP is liable for 1 daily fixed network charge
3. The standard 15c per day fixed charge provides for 20KVA maximum demand
4. Budgeted pass-through charges, including transmission, comprise approximately 26.1% of the line charges
5. Unmetered supply tariffs are wholly fixed.
6. Industrial tariffs for large consumers and Large Distributed Generation are customer specific and wholly fixed charges

					Rate Effective from 1 April 2015			Rate Effective from 1 April 2014				
Tariff / Price Category Code	Price Category Description	Number of ICPs	Tariff Code	Charge Type	Pass-through Component	Distribution Component	Total Line Charge	Pass-through Component	Distribution Component pre discount	Total Line Charge Pre Discount	Distribution Discount Component	Total Line Charge Post Discount
UC	Total charges for this plan include a fixed rate for each day connected (UCF) and a variable rate (UCV) for kWh consumption.	7304	UCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			UCV	cents/kWh	5.386	17.570	22.956	4.450	17.491	21.941	- 11.000	
UCFC	This plan is for 2 or more meters. Total charges for this plan include the UC tariff and a variable rate (FCV) for kWh consumption through at least 1 meter on FC load. Any remaining meters must be on UC or FC load.	356	UCFCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			UCV	cents/kWh	5.386	17.570	22.956	4.450	17.491	21.941	- 11.000	
			FCV	cents/kWh	1.737	4.830	6.567	1.435	4.646	6.081	-	6.081
UCPC	This plan is for 2 or more meters. Total charges for this plan include the UC tariff and a variable rate (PCV) for kWh consumption through at least 1 meter on PC load. Any remaining meters must be on UC or PC load.	382	UCPCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			UCV	cents/kWh	5.386	17.570	22.956	4.450	17.491	21.941	- 11.000	
			PCV	cents/kWh	3.821	12.077	15.898	3.157	11.616	14.773	- 11.000	
UCPCFC	This plan is for 3 or more meters. Total charges for this plan include the UCPC tariff and a variable rate (FCV) for kWh consumption through at least 1 meter on FC load. Any remaining meters must be on UC, PC or FC load.	44	UCPCFCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			UCV	cents/kWh	5.386	17.570	22.956	4.450	17.491	21.941	- 11.000	
			PCV	cents/kWh	3.821	12.077	15.898	3.157	11.616	14.773	- 11.000	
			FCV	cents/kWh	1.737	4.830	6.567	1.435	4.646	6.081	-	6.081
PC	Total charges for this plan include a fixed rate for each day connected (PCF) and a variable rate (PCV) for kWh consumption.	20610	PCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			PCV	cents/kWh	3.821	12.077	15.898	3.157	11.616	14.773	- 11.000	
PCFC	This plan is for 2 or more meters. Total charges for this plan include the PC tariff and a variable rate (FCV) for kWh consumption through at least 1 meter on FC load. Any remaining meters must be on PC or FC load.	705	PCFCF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			PCV	cents/kWh	3.821	12.077	15.898	3.157	11.616	14.773	- 11.000	
			FCV	cents/kWh	1.737	4.830	6.567	1.435	4.646	6.081	-	6.081
DAYNGT	The day rate (DAYV) applies from 7 am to 11 pm and the night rate (NGTV) from 11 pm to 7 am. Total charges for this plan include a fixed rate for each day connected (DAYF), a variable rate for kWh consumption during the day period (DAYV), and a variable rate for kWh consumption during the night period (NGTV).	914	DAYF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			DAYV	cents/kWh	3.995	13.498	17.493	3.301	12.982	16.283	- 11.000	
			NGTV	cents/kWh	0.869	1.989	2.858	0.718	1.913	2.631	-	2.631
CAP150	This plan is for customers on CT Metering, with a capacity of greater than 100 Amps per phase. Total charges for this plan include a fixed rate for each day connected (CAP150F) and a variable rate (CAP150V) for kWh consumption on all loads.	124	CAP150F	$/Day	1.610	6.716	8.326	1.330	6.458	7.788	- 0.550	7.238
	No new ICP's allowed. Ceased 31 March 2015.		CAP150V	cents/kWh	3.576	8.348	11.924	2.955	8.029	10.984	- 0.300	10.684
CAP150FC	This plan is for 2 or more meters. The total charges for this plan include the CAP150 tariff and a variable rate (FCV) for kWh consumption through at least 1 meter on FC load. Any remaining meters must be on CAP150 or FC load. No new ICP's allowed. Ceased 31 March 2015.	8	CAP150FCF	$/Day	1.610	6.716	8.326	1.330	6.315	7.645	- 0.550	7.095
			CAP150V	cents/kWh	3.576	8.348	11.924	2.955	8.029	10.984	- 0.300	
			FCV	cents/kWh	1.737	4.830	6.567	1.435	4.646	6.081	-	6.081
SPECIAL	This plan is for existing ICPs Only - no new ICPs allowed. To be replaced over the next 12 months	72	SPECIALF	$/Day	0.013	0.137	0.150	0.013	0.137	0.150	- 0.135	0.015
			VARIABLE	cents/kWh	As per ICP's metering configuration			As per ICP's metering configuration			- 11.000	
DG	Micro Generation injection less than 20KW		DGF	$/kW/day	-	-	-					
LDG	Embedded generation >1MW. Individual fixed annual contracts for Large Scale Distributed Generation Customer # 1		LDGF	$/day	-	-	-					

					Rate Effective from 1 April 2015			Rate Effective from 1 April 2014				
Tariff / Price Category Code	Price Category Description	Number of ICPs	Tariff Code	Charge Type	Pass-through Component	Distribution Component	Total Line Charge	Pass-through Component	Distribution Component pre discount	Total Line Charge Pre Discount	Distribution Discount Component	Total Line Charge Post Discount
CAP Time of Use (between 30,000 kwh - 200,000 kwh)	The default tariff for all customers with an annual consumption between 30,000 kWh and 200,000 kWh. Total charges for this plan includes a fixed tariff for each day connected (CAPTOUF), and a variable tariff for kWh consumption (CAPV).	0	CAPTOUF	$/Day	1.610	6.716	8.326					
CAPV1	23:00 - 07:00		CAPV1	cents/kWh	0.109	0.270	0.379					
CAPV2	07:00 - 07:30		CAPV2	cents/kWh	3.703	9.191	12.894					
CAPV3	07:30 - 09:30		CAPV3	cents/kWh	5.446	13.516	18.962					
CAPV4	09:30-17:30		CAPV4	cents/kWh	3.703	9.191	12.894					
CAPV5	17:30 - 20:00		CAPV5	cents/kWh	5.446	13.516	18.962					
CAPV6	20:00 - 23:00		CAPV6	cents/kWh	3.703	9.191	12.894					
ToU Time of Use >200,000 Commenced 1.4.2015	The default tariff for all customers with an annual consumption exceeding 200,000 kWh but less than 3,000,000 kWh. Total charges for this plan includes a fixed tariff for each day connected (TOUF), and a variable tariff for	61	TOUF	$/Day	4.876	19.127	24.003					
ToU1V	23:00 - 07:00		TOUV1	cents/kWh	0.122	0.167	0.290					
ToU2V	07:00 - 07:30		TOUV2	cents/kWh	4.164	5.691	9.856					
ToU3V	07:30 - 09:30		TOUV3	cents/kWh	6.124	8.370	14.494					
ToU4V	09:30 - 17:30		TOUV4	cents/kWh	4.164	5.691	9.856					
ToU5V	17:30 - 20:00		TOUV5	cents/kWh	6.124	8.370	14.494					
ToU6V	20:00 - 23:00		TOUV6	cents/kWh	4.164	5.691	9.856					
ToU Time of Use >200,000 Ceased 31.3.2015	The default tariff for all customers with an annual consumption exceeding 200,000 kWh but less than 3,000,000 kWh. Total charges for this plan includes a fixed tariff for each day connected (TOUF), and a variable tariff for		TOUF	$/Day				4.029	18.391	22.420	- 0.550	21.870
ToU1V	00:00 - 04:00		TOUV1	cents/kWh				0.107	0.155	0.262	-	0.262
ToU2V	04:00 - 08:00		TOUV2	cents/kWh				0.161	0.254	0.415	-	0.415
ToU3V	08:00 - 12:00		TOUV3	cents/kWh				3.492	5.574	9.066	- 0.300	
ToU4V	12:00 - 16:00		TOUV4	cents/kWh				4.137	6.591	10.728	- 0.300	
ToU5V	16:00 - 20:00		TOUV5	cents/kWh				5.950	9.499	15.449	- 0.300	
ToU6V	20:00 - 24:00		TOUV6	cents/kWh				1.974	3.085	5.059	- 0.300	
IND1	Individual fixed annual contracts for Industrial Customer # 1	2	IND1	$/Day	-	-	-					
IND2	Individual fixed annual contracts for Industrial Customer # 2	1	IND2	$/Day	-	-	-					
UMLSH	Unmetered supply consisting of Pedestrian Crossing, Streetlights, Bollards, Unmetered Lights with 1 lamp	15	UMLSH	$/Day	-	0.385	0.385	-	0.380	0.380	-	0.380
UMLDH	Unmetered supply consisting of 1 pole with 2 lamps	5	UMLDH	$/Day	-	0.771	0.771	-	0.760	0.760	-	0.760
UMLTH	Unmetered supply consisting of 1 pole with 3 lamps	1	UMLTH	$/Day	-	1.155	1.155	-	1.139	1.139	-	1.139
UMLSHLPMC	Unmetered supply consisting of 1 lamp mounted on a Top Energy Pole e.g. Pedestrian Crossing, Streetlights, Bollards	5	UMLSHLPMC	$/Day	-	0.475	0.475	-	0.468	0.468	-	0.468
UMLDHPMC	Unmetered supply consisting of 2 lamps mounted on a Top Energy Pole	0	UMLDHPMC	$/Day	-	0.860	0.860	-	0.848	0.848	-	0.848
UMLTHLPMC	Unmetered supply consisting of 3 lamps mounted on a Top Energy Pole	0	UMLTHLPMC	$/Day	-	1.246	1.246	-	1.228	1.228	-	1.228
UMDECL	Unmetered supply consisting of String lighting of Incandescent light bulbs	2	UMDECL	$/Day	-	0.385	0.385	-	0.380	0.380	-	0.380
UMGL	Unmetered supply consisting of Community Lighting, Convenience Lighting, Jetty Lights, Under Verandah Lighting	4	UMGL	$/Day	-	0.129	0.129	-	0.127	0.127	-	0.127
UMGLLPMC	Unmetered supply consisting of Community Lighting, Convenience Lighting, Jetty Lights mounted on a Top Energy pole	0	UMGLLPMC	$/Day	-	0.218	0.218	-	0.215	0.215	-	0.215
UMCON500	Unmetered continuous supply less than 500watts e.g. Battery Chargers, Electric Fences, Irrigation, PCM Cabinets, Phone Booths, Radio Repeaters, TV Boosters	181	UMCON500	$/Day	-	0.372	0.372	-	0.367	0.367	-	0.367
UMINT	Unmetered intermittent supply consisting of Fire Sirens, Railway Crossing Lights, Traffic Counters	7	UMINT	$/Day	-	0.206	0.206	-	0.203	0.203	-	0.203

Additional conditions and clarifications

Excluding Planned and Unplanned Outages, energy supply for the load connected to at least one meter of each Tariff is expected to occur 24 hrs each day without restriction excluding any partially controllable (PC) or fully controllable load (FC) offered to Top Energy.

1. **FC**: Top Energy can control the Fully Controllable Load for up to 4 hrs per day and the load offered must be at least 10 kW. The maximum load control relay is 40amps and customer will need to provide an additional contactor for this tariff.
2. **PC**: Top Energy can control the Partially Controllable Load for up to 6 hrs per day and the load offered must be at least 3 kW (e.g. a hot water cylinder).
3. **DAYNGT**: To qualify for this plan customers must offer at least 3 kW of load controllable by Top Energy for up to 6 hrs per day.
4. The maximum combination loading for Whole Current Meters is 100 amps across all elements, with the maximum on any second element being 40 amps. Installers are responsible for ensuring specified load on meter elements in not exceeded.
5. Applicable for new and altered connections from 1 April 2015. Any ICP can have a maximum of one import and one export tariff.