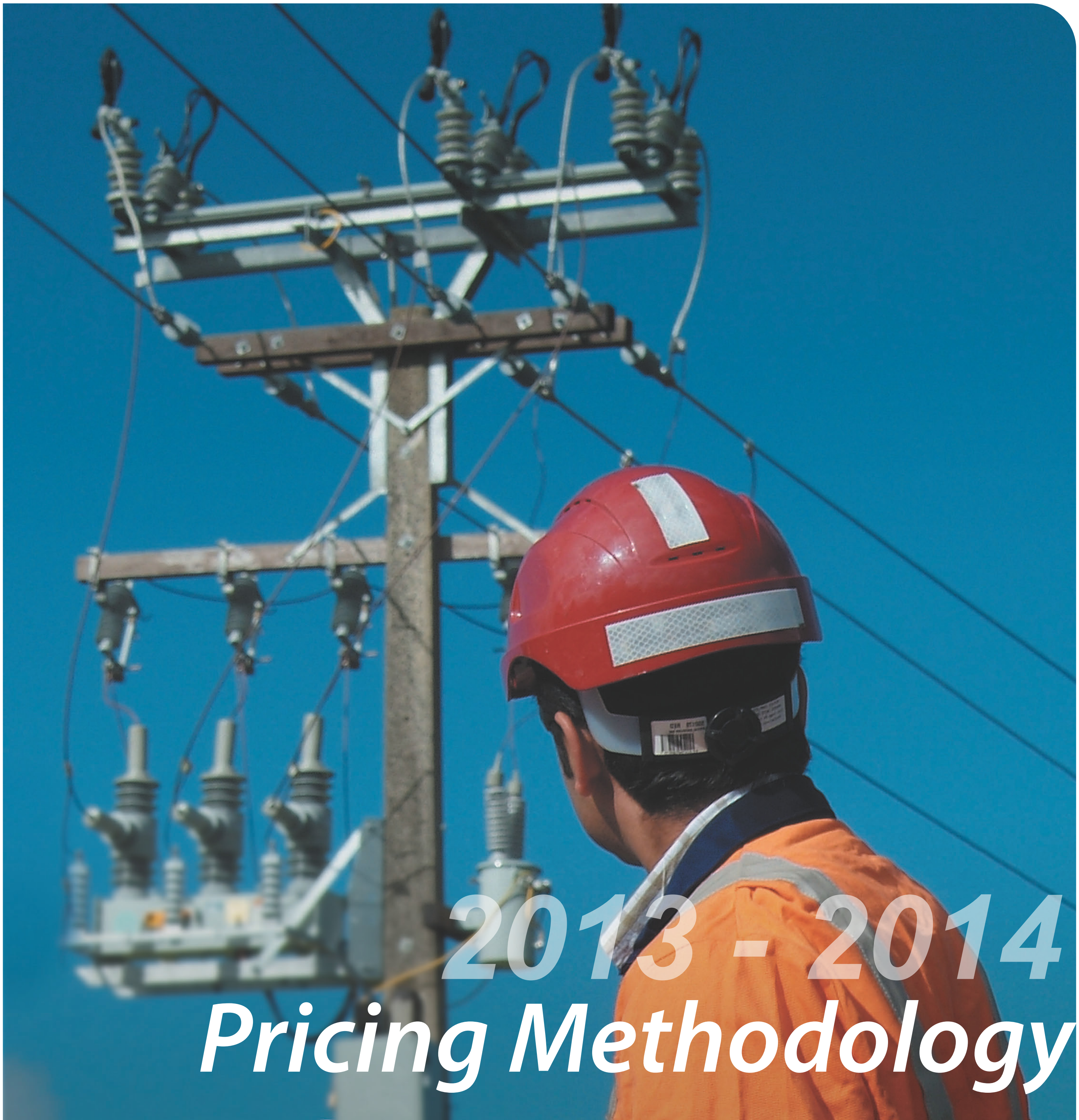
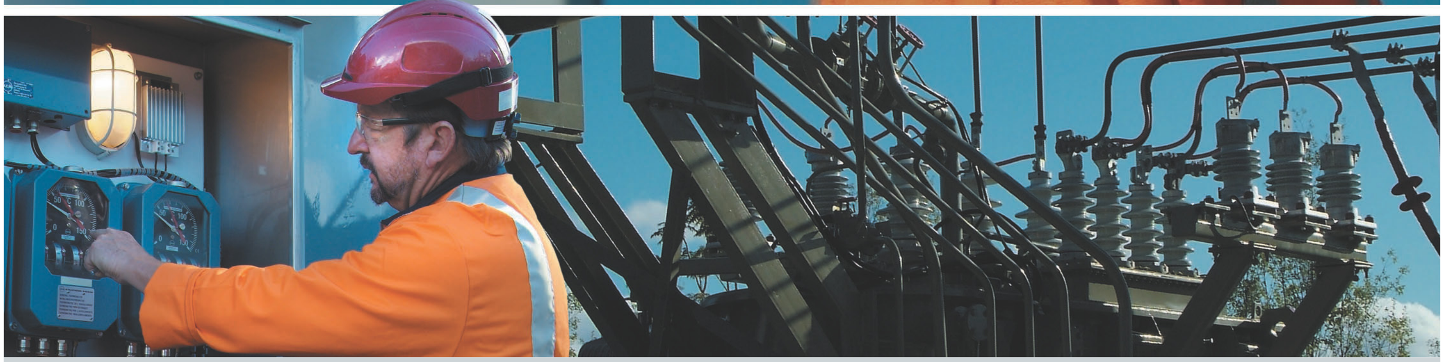


2013 - 2014
Pricing Methodology



For Line Charges, effective 1 April 2013 to 2014

(Pursuant to Electricity Information Disclosure Requirements, 22 & 23.)

March 2011

www.topenergy.co.nz

TOP ENERGY®
Te Puna Hihiko

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Terms and Definitions

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.
Capacity Measurement Period	12-month period starting 1 September and ending 31 August inclusive, immediately prior to the commencement of the pricing year.
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
Embedded Generation	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.
Consumer	A purchaser of electricity from the Retailer where the electricity is delivered via the distribution network.
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.
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.

1. Introduction

The purpose of this document is to describe Top Energy Limited's (TEL) pricing methodology for the line charges effective from 1 April 2013 to 31 March 2014. The pricing methodology disclosure document is subject to review annually or as required.

This document has been prepared to comply with the Electricity Authority's pricing methodology disclosure guidelines and the requirements specified in 2.4 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 issued 1 October 2012 (Determination). References to various Determination clauses are made within this document.

During 2009, TEL conducted an extensive public consultation exercise regarding its proposed network development and their expectations regarding price and quality (clause 2.4.1 (4)). This was done by means of public notification and a telephone survey that posed a number of questions to customers relating to power quality and price. The survey results established that 80% of consumers wished to see the reliability to the Northern area improve and that 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. This set the scene for TEL's subsequent Asset Management Plans and contributed to the development of the pricing strategy for the 5 year regulatory period from 1 April 2010 to 31 March 2015.

TEL's present pricing strategy (clause 2.4.4) was established by its board of directors at the meeting on 18 December, 2012. The board accepted a paper from the Chief Executive on the subject: *Network Pricing and Discount Application from April 2013*. The paper precluded changes to the overall structure of existing tariffs and continued with the inter-group re-balancing that began with the 2010 pricing review, in order to progressively reduce the on-going cross subsidy from the commercial groups to the mass-market group (clause 2.4.4 (2)). TEL's pricing methodology is consistent with the distribution pricing principles as published by the Electricity Commission in March 2010 and adopted by the Electricity Authority (clause 2.4.3 (2)). The Electricity Authority is currently undertaking a consultation process with a view to amending the principles.

The present pricing strategy is expected to apply until the end of the current 5 year DPP period, or 31 March 2015. This means that for customers other than IND, price increases will be limited to increases in the CPI indices over the applicable pricing period (clauses 2.4.3 (6) and 2.4.4(1)). Consequently, for the pricing year to 31 March 2014, the overall revenue increase from the previous pricing year will be limited to the applicable change in the CPI. This additional revenue will be derived from increases to the variable parts of the mass-market tariffs.

This pricing methodology document discloses:

- The methodology used to calculate the prices charged;
- The key components of revenue required to cover costs and profits of the lines business activities;
- The consumer groups used to calculate the prices being charged, including:
    - The rationale for consumer grouping;
    - The method of determining which groups consumers are in;
    - The statistics relating to each consumer group.
- The method and rationale by which components of the revenue are allocated to consumer groups, and the numerical values of the different components;
- The rationale and method used to determine the proportions of charges which are fixed and the proportions which are variable.

The line charge is based on each individual installation control point (ICP) and on the kWh consumption data provided by the respective retailers operating on TEL's network.

For mass market customers and small to medium businesses, transmission charges are bundled with the disclosed distribution charges, and included in the appropriate tariff component. For TEL's large industrial

(IND) customers, it is possible to pass on transmission charges in a direct and transparent fashion which provides efficient pricing signals to the customers.

The objectives of the pricing methodology are:

- To allocate costs fairly between consumer groups;
- To establish a range of tariff options that reflect/meet consumer requirements;
- To provide appropriate demand based pricing signals where possible;
- To meet regulatory requirements;
- To appropriately recover pass through costs;
- To achieve a rate of return acceptable to shareholders.

When this pricing methodology disclosure document has been approved by the board, it will be published on the Top Energy website www.topenergy.co.nz

2. Pricing Objectives

2.1 Revenue Requirements

Pricing should generate sufficient revenue for TEL to meet the following requirements, while also ensuring that TEL does not breach the regulated price path:

1. Meet its contractual obligations for connection to the Transpower Grid.

2. Meet its contractual obligations for the delivery of energy over its distribution network to the consumers.

3. Meet the Company's objective to fund:

    - All operating costs of the lines business, including:
        - Grid Associated Transmission Costs
        - Maintenance Costs
        - Overheads and Taxation Costs
    - New investments
        - Capital Expenditure

4. Comply with the statutory requirements on public safety, regulatory disclosure, environmental protection and quality of supply

To achieve the above, TEL has the following five guiding principles for pricing:

1. Provide pricing which is economically efficient, transparent, simple to understand, implement and administer, and which accommodates the different socio-economic needs of its customers.

2. Avoid significant price shocks either within of between customer groups so as to maintain price stability and certainty.

3. To not differentiate between its urban and rural customers.

4. Where practical, to provide customers the opportunity to significantly reduce their electricity costs, if they reduce their usage at times when TEL's associated costs of supply are high.

5. Within the restrictions of the government's price control regime, to provide an adequate return to the shareholder.

2.2 Efficiency

Pricing must be economically efficient in the investment signals it creates. This is achieved by matching the pricing structure to the cost structure as closely as is practicable.

The Electricity Authority published its Distribution Pricing Principles in February, 2010. These principles outline the requirements for distributors' pricing methodology. Pricing principle (a) (i) in the Pricing Principles and Guidelines states:

"Prices are to signal the economic costs of service provision, having regard, to the extent practicable, to the level of available service capacity"

In order to create useful signals for its customers, TEL employs a very simple pricing structure that displays the fixed and variable prices of electricity distribution by customer category. This structure also enables TEL to achieve consistency with the Distribution Pricing Principles to the maximum practicable extent (clause 2.4.3(2)).

For commercial (or ToU) customers TEL charges higher prices during periods of high electricity demand and lower prices during low demand periods. This reflects the fact that significant proportions of distribution costs are established by transmission costs and by the need to provide network assets that are able to cope with demands at peak times. In both cases, related costs will be increased if demands at peak times are higher and *vice versa.*

For domestic (or NToU) customers, there is a range of tariff options that reflects the nature of the load connected and whether TEL is able to shift this load to alleviate transmission peak charges.

For large industrial (or IND) customers, the pricing is based directly on coincident peak charges, and this provides clear incentives for users to manage their electricity usage.

2.3 Fairness

In order to ensure that the prices set are fair and reasonable, TEL divides its customers into different consumer groups based on their load capacities, and sets their prices in a way to reflect their share of assets used during the pricing year.

When new investment is required, those users who obtain the benefit are required to contribute towards the cost. Notwithstanding this general policy, where a sufficiently large proportion of TEL customers across diverse consumer groups receive a benefit from a new investment, these costs may be recovered across the whole consumer base.

Pricing is also even-handed in its treatment of different retailers, and provides for equal access as required by the Distribution Pricing Principles and the Code.

2.4 Simplicity

TEL uses a very simple pricing structure that is easy to understand and administer, so that it can reduce the cost and complexity of its billing system, whilst providing effective commercial signals that allow consumers to make efficient investment decisions.

As a result, TEL has bundled its transmission and distribution charges for all customers except large industrial (IND).

2.5 Load Management

It is desirable that any signal incorporated in the pricing is passed through to the customers in a form that will allow them to respond positively. The pricing methodology employed by TEL provides the correct signals to encourage demand side management.

Domestic customers will observe benefits from the different tariff rates offered if they allow part of their load to be controlled by TEL's load control equipment. Industrial customers are able to see direct benefits from any avoided transmission charges in their line charges if they shift demand away from TEL's AMD and RPDP peak periods.

2.6 Legislative Compliance

Electricity lines companies within New Zealand are classified into one of two regulatory controlled categories; either "consumer owned" or "non-consumer owned". Top Energy, although 100% owned by the Top Energy Consumer Trust, does not meet the criteria of being "consumer owned", owing to the current appointed trustee arrangement, rather than the "fully elected" status required for exemption to price-quality regulation.

Price-quality regulation is detailed under Sub Part 9 of Part 4 of the Commerce Act 1986 (the Act). Default/Customised Price-Quality regulation replaces the previous Part 4 thresholds regime and enables the Commerce Commission to set Default Price Paths for a 5 year regulatory period which must be followed by the regulated companies. If the lines companies are not satisfied with the details of the Default Price Path, they can apply to the Commerce Commission for an individual Customised Price Path for the same regulatory period.

The Default Price Path allows for the lines company to seek a return on investment (ROI) equivalent to its Weighted Average Cost of Capital (WACC). The allowable WACC for the current regulatory period (2010-2015) has been set at the 8.77% (75th percentile vanilla WACC). Based on the finalised WACC, Top Energy has been allowed a price increase of 10% + CPI for each of the 2014 and 2015 pricing years. Notwithstanding these allowable increases, the Top Energy board has decided to limit the price increase to CPI in the 2013 to 2014 pricing year.

3. Revenue Requirements (clause 2.4.3)

The first step in developing the pricing methodology is to establish the annual costs and revenue requirements. Costs can then be allocated among different consumer groups.

Forecast revenue requirements provide agreed returns and meet TEL's objectives to, where possible, fund capital expenditure from current earnings (clause 2.4.3 (3) & (4).

COST COMPONENT	REGULATORY REVENUE REQUIREMENT (1 April 2013 to 31 March 2014)
Transpower Transmission Cost recovery	$5,583,489
Top Energy Transmission Cost Recovery	$1,711,070
Avoided Transmission Charges	$2,294,765
Other Pass-through Costs	$168,702
Transmission subtotal	**$9,758,026**
Network Maintenance Costs	$5,550,000
Overheads	$5,832,595
Depreciation	$6,469,241
Return on Assets	$15,123,784
Distribution subtotal	**$32,975,620**
Annual Revenue Requirement	**$42,733,646**
Allowable Revenue Foregone (refer 1. Introduction)	($4,556,224)
TOTAL TARGET REVENUE	**$38,177,422**

3.1 Transmission Cost Recovery

Since 1 April 2012, TEL has been connected to Transpower's system at Top Energy's 110 kV substation at Kaikohe.

In accordance with the regulatory regime and its own pricing principles, TEL passes through all the transmission charges without any mark-up. The transmission charge is equitably distributed across all customers connected to TEL's network.

Transmission revenue requirements are calculated by Transpower. These charges include:

- Connection Charges (annual capacity charges, based on associated transmission connection assets);
- Interconnection Charges (coincident peak charges, based on TEL's RCPD in the demand measurement period);
- New investment charges (determined via the agreement between Transpower and TEL as to capacity and security upgrades).

Far North transmission assets were transferred from Transpower to Top Energy on 1 April, 2012. This resulted in a decrease in Connection Charges.

A notional transmission connection charge has therefore been incorporated in TEL's pricing as part of the transmission pass-through cost, with the amount being based on section 11.4 of the Commerce Commission's Electricity Distribution Services Default Price-Quality Path Determination 2012.

For large industrial customers, Transpower's interconnection charge is allocated based on the customer's contribution to that charge. As all these customers have ToU metering, TEL is able to determine this contribution by using the twelve half-hourly demands that are coincident with TEL's RCPD.

For the remaining customers on TEL network, transmission charges are allocated based on demand and to maintain historical relativities and avoid price volatility.

Transpower's losses and constraint rebates are excluded from the revenue requirement calculations as they are volatile and difficult to predict with any degree of accuracy.

In the event that savings in transmission and other charges arise during the year which cause TEL to breach its default price path, any excess revenue will be refunded either as an one-off distribution to consumers or by an adjustment to subsequent pricing; depending upon the magnitude of these savings.

3.2 Avoided Transmission Cost Recovery

Avoided transmission and voltage support charges may be payable to embedded generators of greater than 1MW output, when suitable terms have been negotiated with TEL. This situation applies to generators that are connected to the TEL's network and have actively contributed to reducing TEL's contribution to the Regional Coincident Peak Demand (RCPD), as measured during Transpower's annual measurement period for that pricing year.

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.

3.3 Maintenance of Existing Assets

The maintenance program is driven by the need to provide consumers with acceptable levels of safety, reliability and repairs to equipment following faults. The amount budgeted for maintenance work is determined by the TEL's 2013 Asset Management Plan.

4. How We Price (Clause 2.4.3)

TEL's approach to pricing is that all customers who are connected to the network should pay their fair share of the revenue requirement. The tariffs are structured so that those who use the network during peak times pay a premium, and those that don't pay less. TEL has also adopted a policy of maintaining uniform geographic pricing for all its customers - excepting large industrial customers, which are individually priced.

Line charges are disaggregated into three consumer groups, which reflect the share of assets used and typical maximum demands of the individual customer groups, as set out in the following table (clause 2.4.3 (5)). For industrial customers, it is possible to accurately calculate both Transpower's costs and the costs of TEL's distribution service, so that these can be passed on transparently to the customers concerned. Pricing for ToU customers is structured to reflect typical electricity retailers' pricing structures. That is, the variable part of the distribution tariff changes depending on the time of day that the electricity is consumed. The rationale for this approach is that it encourages demand reduction at peak periods, thus potentially reducing TEL's need to provide related distribution equipment. The remaining customers are grouped as NToU and these provide the majority of TEL's network revenue. The cost of servicing these customers is mainly related to both their share of the network demands at peak periods and to their geographic distribution. Given existing regulatory, pricing policy and other practical constraints, the variable per kWh charge is considered to be a reasonable and practicable proxy for meeting TEL's related costs.

Consumer Group	Customer Description	Typical Maximum Demand	Number of ICPs
IND	Industrial Customers	Capacity > 1MVA, and annual consumption > 3GWh	3
ToU	Commercial Customers	Annual consumption > 2GWh but < 3GWh	61
NToU	Small Businesses (i.e. CAP150)	Capacity > 100A per phase	114
	Small Businesses / Residential Customers (i.e. DAYNGT)	Annual consumption > 8000kWh	903
	Residential Customers	Annual consumption < 8000kWh	29,039
	Unmetered Supply	Annual consumption < 3000kWh	217
Total			**30,337**

The transport of electricity is a capital intensive undertaking. A large part of the costs of delivering electricity to customers is fixed, as it is linked to the provision and upkeep of the assets used to supply customers; that is, costs do not vary with the amount of energy conveyed or consumed. A relatively small portion of input costs into the business are variable with demand; for example, transmission and avoided transmission charges. The proportion of the input costs that vary with the quantity energy used (kWh) is extremely small.

In setting the ratio of fixed to variable revenue, there are a number of considerations that must be made. The ratio of fixed to variable revenue has been calculated to meet a number of requirements, including:

- Legislative requirements (e.g. low fixed charge)
- Reflect cost to supply and the nature of these costs
- Encourage demand side load management
- Reduce bypass or cross-subsidy risk
- Optimise maintenance and capital work
- Meet consumer requirements
- Reduce commercial risk

TEL currently derives approximately 8% of its overall distribution revenue from fixed components, and 92% from variable components. A breakdown of the fixed and variable percentages of revenue from each consumer group is given in the table below (clause 2.4.3(8)):

Consumer Group	Customer Description	Fixed Charge as a Percentage of the Group Revenue	Variable Charge as a Percentage of the Group Revenue
IND	Industrial Customers	100%	0%
ToU	Commercial Customers	15%	85%
NToU	Small Businesses (i.e. CAP150)	22%	78%
	Small Businesses / Residential Customers (i.e. DAYNGT)	0%	100%
	Residential Customers	1%	99%
	Unmetered Supply	100%	0%
Overall		**8%**	**92%**
Last Year		**8%**	**92%**

4.1 Large Industrial Customers (clause 2.4.5)

Top Energy has a fixed annual tariff for its large industrial (IND) customers, which have entered into non-standard Use of System Agreements (UoSAs) (clause 2.4.5 (1)). The tariffs for large industrial customers comprise:

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

The charges have been calculated on the basis of:

- Associated assets used
- Customer's consumption
- Customer's coincident peak demand

Pricing for IND aims to recover the actual costs of TEL's service, so as to be consistent with the pricing principles. To meet these customers' requirements, the charges are wholly fixed and divided into twelve equal payments. There are no variable charges assessed.

TEL does not have additional obligations or responsibilities regarding interruptions in its non-standard contracts beyond those incorporated in its standard contracts (clause 2.4.5 (2)).

4.2 Time of Use Commercial Customers

Historical consumer groupings have been retained to provide customers with a degree of stability. TEL's pricing structure for the commercial market has a fixed and variable component. These customers are all on standard contracts.

Fixed charges for commercial customers have been set to maintain historical linkages and to reflect the proportion of asset used.

The variable component encourages demand side management from commercial customers, since variable rates are higher during periods of high electricity demand and lower during off-peak demand periods.

A description of the ToU tariff category; and their associated fixed and variable rates are provided in Appendix 1.

4.3 Non Time of Use Domestic and Small Commercial Customers

TEL's pricing structure for domestic and small commercial customers (except unmetered supply) also has a fixed and variable component. Pricing for unmetered supply has a fixed daily charge only.

The fixed charge is set at 15 cents per day (GST exclusive) for all residential customers, so as to comply with the requirements of S172B of Part 4A of the Commerce Act 1986. This fixed charge contributes a small portion of the revenue required, but this is not nearly sufficient to meet all the costs of supply.

A separate fixed charge is set for small business customers in order to reflect a different level consumption and demand requirements compared to residential customers.

The variable component of the revenue required is generally based on domestic customers (except unmetered supply) pro-rata contribution towards the total demand.

Unmetered supply (including streetlights) pricing is wholly fixed.

A description of different tariff categories and valid combinations of tariffs is provided in Appendix 1.

4.4 Distributed Generation (Clause 2.4.5 (3))

Top Energy has not developed separate or additional prices or payments for consumers that own distributed generation. It is considered that customers with distributed generation already benefit from reduced network variable distribution charges, to the extent that electricity generated on site reduces the amount of electricity delivered via the network, and thus the related variable charges. Conversely, the cost to Top Energy of servicing these customers is not reduced by the presence of the distributed generation.

4.5 Capital Contributions (Clause 2.4.6)

TEL's methodology for determining capital contribution is publically disclosed on the website www.topenergy.co.nz

5. Allocation Method (clause 2.4.3)

Section 4 above describes the pricing methodology used by TEL for each consumer group. In summary, as shown in the table below, revenue is allocated based on each consumer group's associated assets and energy consumption. Allocation of costs to each consumer group based on reflecting the actual cost of supply would result in significant increases in some tariff rates, which would create distortions from historical pricing and introduce pricing volatilities.

				Transmission $'000	Distribution $'000's						
Consumer Group	Regulatory Investment Value Forecast 2014($m)	Number of ICPs	Energy Consumption (MWh)	Transmission and Other Pass-through Costs	Maintenance	Overheads	Depreciation	ROA	Total Revenue Requirement	Impact of Regulatory Regime	Total Target Revenue
IND	3	3	60,166	1,289	86	90	100	235	1,800	(146)	1,654
TOU	8	60	37,979	1,089	271	284	316	738	2,697	433	3,130
NTOU	161	30,548	235,835	7,381	5,193	5,458	6,053	14,151	38,236	(4,843)	33,393
Total				-							
	172	30,611	333,980	9,758	5,550	5,833	6,469	15,124	42,734	(4,556)	38,177

The table above reflects the budgeted costs for the financial year to 31st March 2014.

Transmission and avoided transmission charges are levied by the national grid operator Transpower, Top Energy and the local generator, Ngawha Generation Ltd.

Maintenance and operations are direct costs and relate to maintenance, management, design and planning of the network assets. Indirect costs including overheads, corporate charges etc, which relate to charges such as salaries, directors fees, audit fees and other similar items.

In general, budgeted pass-through charges, including transmission and avoided transmission costs, comprise approximately 23% of the total network line charges.

6. Loss Factors

Losses represent the portion of electricity entering the network, which is consumed during the delivery to customers' installations. The quantity of electricity metered at customer installations is after losses and in order to determine each retailer's purchase responsibilities, the electricity measured at the customer's meter has to be multiplied by a loss factor. There are two main components to the distribution losses:

One is called "technical losses", which itself can be further divided into two components:

- A fixed component due to the standing losses of the zone substation and distribution transformers, and
- Variable components arising from the heating effects of the resistive losses in the delivery conductors. The resistive losses are proportional to the square of the load current and occur in the 110kV, 33kV, 22kV, 11kV and LV network conductors, the zone substations and distribution transformers.

The other main component to the loss is the "non-technical losses", which include unaccounted energy due to theft, meter inaccuracy and billing errors. Due to the lack of historical loading and modelling data, it is impossible to calculate the load losses on the LV network. Therefore, TEL treats LV network losses as a part of non-technical Losses.

The Electricity Industry Participation Code 2010 (Code) requires site-specific loss factors to be calculated for any individual customer with actual or forecast load of more than 40GWh per annum or an electrical demand of more than 10MW. Therefore, as shown in the table below, TEL calculates loss factors for each industrial customer. Owing to the number and diversity of the customers connected to the distribution network, it is not feasible either to measure or to calculate the losses caused by each individual customer. Instead, a general loss factor for all other customers has been determined.

The following loss factors can be applied to reconcile the difference between ICP and GXP meter readings. These are applicable to all time periods, at both GXPs and all network locations.

		Loss Factors - Consumption Effective from 1 April 2013			Loss Factors - Generation Effective from 1 April 2013		
Loss Category Code Used in the Registry	ICP Number / Description	Reconcilliation Loss Factor	Technical Loss Factor	Non-technical Loss Factor	Reconcilliation Loss Factor	Technical Loss Factor	Non-technical Loss Factor
GLV	Flat loss factor applies to all ICP's except Site-specific generation plant (i.e. GEN) and customers (i.e. INDs)	1.1124	1.0648	1.0476	1.0000	1.0000	N/A
IND1	ICP 0000984310TEBBE	1.0290	1.0290	N/A	1.0000	1.0000	N/A
	ICP 0000930130TE465	1.0290	1.0290	N/A	1.0000	1.0000	N/A
IND2	ICP 0000984000TE210	1.0740	1.0740	N/A	1.0000	1.0000	N/A
GEN1	ICP 0000003490TE5AE	1.0000	1.0000	1.0000	1.0000	1.0000	N/A

Note that the allocation of losses is not a contracted line function service and TEL does not charge specific recoveries for losses

Appendix 1 – Network Line Charges 2013-2014

DISCLOSURE OF ELECTRIC LINE CHARGES

Effective from 1st April 2013

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 and recoverable charges, including transmission, comprise approximately 22.5% of the line charges.
5. Unmetered supply tariffs are wholly fixed.
6. Industrial tariffs for large consumers are customer specific and are wholly fixed.

					Rate Effective from 1 April 2013					Rate Effective from 1 April 2012				
Tariff / Price Category Code	Price Category Description	Number of ICPs	Tariff Code	Charge Type	Transmission Charge	Distribution Charge pre-Discount	Total Line Charge pre-Discount	Distribution Discount - See Discount Notes	kWh Discount Cap - See Discount Notes	Transmission Charge	Distribution Charge pre-Discount	Total Line Charge pre-Discount	Distribution Discount - See Discount Notes	kWh Discount Cap - See Discount Notes
UC	Total charges for this plan include a fixed rate for each day connected (UCF) and a variable rate (UCV) for kWh consumption.	7111	UCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			UCV	cents/kWh	3.966	16.752	20.718	- 11.000	1,130	3.525	16.550	20.075	- 11.000	1,130
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.	386	UCFCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			UCV	cents/kWh	3.966	16.752	20.718	- 11.000	1,130	3.525	16.550	20.075	- 11.000	1,130
			FCV	cents/kWh	1.279	4.450	5.729	-	0	1.137	4.396	5.533	-	0
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.	371	UCPCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			UCV	cents/kWh	3.966	16.752	20.718	- 11.000	1,130	3.525	16.550	20.075	- 11.000	1,130
			PCV	cents/kWh	2.814	11.125	13.939	- 11.000		2.501	10.991	13.492	- 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.	51	UCPCFCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			UCV	cents/kWh	3.966	16.752	20.718	- 11.000	1,130	3.525	16.550	20.075	- 11.000	1,130
			PCV	cents/kWh	2.814	11.125	13.939	- 11.000		2.501	10.991	13.492	- 11.000	
			FCV	cents/kWh	1.279	4.450	5.729	-	0	1.137	4.396	5.533	-	0
PC	Total charges for this plan include a fixed rate for each day connected (PCF) and a variable rate (PCV) for kWh consumption.	20382	PCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			PCV	cents/kWh	2.814	11.125	13.939	- 11.000	1,130	2.501	10.991	13.492	- 11.000	1,130
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.	738	PCFCF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			PCV	cents/kWh	2.814	11.125	13.939	- 11.000	1,130	2.501	10.991	13.492	- 11.000	1,130
			FCV	cents/kWh	1.279	4.450	5.729	-	0	1.137	4.396	5.533	-	0
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	903	DAYF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			DAYV	cents/kWh	2.942	12.434	15.376	- 11.000	1,130	2.615	12.284	14.899	- 11.000	1,130
			NGTV	cents/kWh	0.640	1.832	2.472	-	0	0.569	1.810	2.379	-	0
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.	109	CAP150F	$/Day	1.267	6.185	7.452	- 0.550		1.126	6.110	7.236	- 0.550	
			CAP150V	cents/kWh	2.814	7.690	10.504	- 0.300	1,092,500	2.501	7.597	10.098	- 0.300	1,092,500
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.	5	CAP150FCF	$/Day	1.267	6.110	7.377	- 0.550		1.126	6.110	7.236	- 0.550	
			CAP150V	cents/kWh	2.814	7.690	10.504	- 0.300	1,092,500	2.501	7.597	10.098	- 0.300	1,092,500
			FCV	cents/kWh	1.279	4.450	5.729	-	0	1.137	4.396	5.533	-	0
SPECIAL	**This plan is for existing ICPs Only - no new ICPs allowed.**	79	SPECIALF	$/Day	0.013	0.137	0.150	- 0.135		0.013	0.137	0.150	- 0.135	
			VARIABLE	cents/kWh	As per ICP's metering configuration	-	-	As per ICP's metering configuration		As per ICP's metering configuration	-	-	As per ICP's metering configuration	
ToU Time of Use	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 kWh consumption (TOUV).	61	TOUF	$/Day	3.837	17.794	21.631	- 0.550		3.411	17.794	21.205	- 0.550	
ToU1V	00:00 - 04:00		TOUV1	cents/kWh	0.102	0.150	0.252	-	0	0.091	0.150	0.241	-	0
ToU2V	04:00 - 08:00		TOUV2	cents/kWh	0.153	0.246	0.399	-	0	0.136	0.246	0.382	-	0
ToU3V	08:00 - 12:00		TOUV3	cents/kWh	3.326	5.393	8.719	- 0.300	1,092,500	2.956	5.393	8.349	- 0.300	1,092,500
ToU4V	12:00 - 16:00		TOUV4	cents/kWh	3.940	6.377	10.317	- 0.300		3.502	6.377	9.879	- 0.300	
ToU5V	16:00 - 20:00		TOUV5	cents/kWh	5.667	9.191	14.858	- 0.300		5.037	9.191	14.228	- 0.300	
ToU6V	20:00 - 00:00		TOUV6	cents/kWh	1.880	2.985	4.865	- 0.300		1.671	2.985	4.656	- 0.300	
IND1	Individual fixed annual contracts for Industrial Customer 1.	2	IND1	$/Day	2,917.63	976.35	3,893.98	- 19.06	0	2,761.84	905.60	3,667.44	- 19.06	0
IND2	Individual fixed annual contracts for Industrial Customer 2.	1	IND2	$/Day	404.73	291.06	695.79	- 19.06	0	382.64	334.13	716.77	- 19.06	0
UMLSH	Unmetered suppy consisting of Pedestrian Crossing, Streetlights, Bollards, Unmetered Lights with 1 lamp.	7	UMLSH	$/Day	-	0.380	0.380	-	0	-	0.380	0.380	-	0
UMLDH	Unmetered supply consisting of 1 pole with 2 lamps.	5	UMLDH	$/Day	-	0.760	0.760	-	0	-	0.760	0.760	-	0
UMLTH	Unmetered supply consisting of 1 pole with 3 lamps.	1	UMLTH	$/Day	-	1.139	1.139	-	0	-	1.139	1.139	-	0
UMLSHLPMC	Unmetered supply consisting of 1 lamp mounted on a Top Energy Pole eg Pedestrian Crossing, Streetlights, Bollards.	5	UMLSHLPMC	$/Day	-	0.468	0.468	-	0	-	0.468	0.468	-	0
UMLDHPMC	Unmetered supply consisting of 2 lamps mounted on a Top Energy Pole.		UMLDHPMC	$/Day	-	0.848	0.848	-	0	-	0.848	0.848	-	0
UMLTHLPMC	Unmetered supply consisting of 3 lamps mounted on a Top Energy Pole.		UMLTHLPMC	$/Day	-	1.228	1.228	-	0	-	1.228	1.228	-	0
UMDECL	Unmetered supply consisting of String lighting of Incandescent light bulbs.	2	UMDECL	$/Day	-	0.380	0.380	-	0	-	0.380	0.380	-	0
UMGL	Unmetered supply consisting of Community Lighting, Convenience Lighting, Jetty Lights, Under Verandah Lighting.	4	UMGL	$/Day	-	0.127	0.127	-	0	-	0.127	0.127	-	0
UMGLLPMC	Unmetered supply consisting of Community Lighting, Convenience Lighting, Jetty Lights mounted on a Top Energy pole.		UMGLLPMC	$/Day	-	0.215	0.215	-	0	-	0.215	0.215	-	0
UMCON500	Unmetered continuous supply less than 500watts eg Battery Chargers, Electric Fences, Irrigation, PCM Cabinets, Phone Booths, Radio Repeaters, TV Boosters.	188	UMCON500	$/Day	-	0.367	0.367	-	0	-	0.367	0.367	-	0
UMINT	Unmetered intermittent supply consisting of Fire Sirens, Railway Crossing Lights, Traffic Counters.	5	UMINT	$/Day	-	0.203	0.203	-	0	-	0.203	0.203	-	0

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.

General Notes

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
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. From 1 April 2012 electricity retailers will include in their invoices Top Energy line charges based on the "Total Line Charge pre-Discount" rates as set out in this table

Discount Notes

1. Discounts will only be provided to consumers that are connected on 22 October 2013 and that have used more than 1 kWh during the 12 month period ending 31 August 2013.
2. The Tariff Category Code used at 31 August 2013 by an ICP will be used to determine the discount.
3. Variable distribution discounts will be applied to consumption up to the kWh Discount Cap, as outlined in the schedule above. Additional consumption above this cap will not receive a discount.