The Lines Company

Pricing Methodology for Lines Charges introduced 1st April 2012

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Introduction

“The *distribution* pricing methodology sets out the methodology under which *distribution* charges are calculated, with a view to recovery by *The Lines Company* of the full economic costs of providing the *distribution* services”

(Transmission Pricing Methodology; Electricity Authority Website. 17 March 2012) *Italics show changes.*

The Lines Company network is primarily rural, it has a relatively low population density and it has the highest percentage of lines on any network that were originally funded heavily through the old RERC subsidies. Customers in The Lines Company network pay The Lines Company for the provision of an electricity distribution service. As a natural monopoly and provider of an essential service, The Lines Company faces considerable regulatory and statutory obligations. The Commerce Commission and the Electricity Authority monitor compliance on behalf of the consumer.

The Lines Company has identified three factors in an electricity distribution cost recovery model;

- the kW load an individual customer places on the local network,
- the capacity that the network is required to supply to the ICP,
- the dedicated assets that are required to facilitate the supply.

There are three factors that contribute to the cost allocation methodology that is used in development of customer groups and tariffs.

- The voltage that supply is taken at.
- The ICP density at the location of the installation point
- The geographical region in which the installation point is located.

A pricing methodology must reflect the cost of supply, within the regulated maximum allowable revenue threshold. This threshold is established using input methodology set by the Commerce Commission and based on asset values and historical quantities. To provide revenue within this threshold, TLC uses three pricing mechanisms;

- the measurement and charging of kW load,
- the measurement and charging of Chargeable Capacity,
- the valuation and charging of dedicated assets.

The Lines Company is committed to kW load charging for its services, based on the premise of after diversity contribution to local peak load. This is measured when the ad at an individual Installation Connection point (ICP) coincides with a period of peak load on the local network. It is this level of load (kW load) that determines the size of the network and the required level of operational and capital expenditure.

As metering technology improves the measurement of kW load will be improved and as a result better management of individual load will be possible for the customer. This identification and management of demand will enable The Lines Company to avoid unwanted and unnecessary capital expenditure which will be for the long-term benefit of its customers.

Glossary

This glossary is intended to;

1. define industry standard terminology where applicable.
2. identify concepts and terms that are used procedurally within The Lines Company,

Industry standard terminology used:

Unless otherwise noted the definitions utilised in the Interpretation section of the Electricity Industry Participation Code 2012 have been used.

Advanced meter: A meter that offers two-way remote communication, and recording of electricity in half-hourly values (rather than a cumulative register), and which can be remotely reprogrammed to activate additional functionality. (fact sheet #1, Smart meters, August 2011, Electricity Authority)

Capacity: the capability of the network to convey electricity under a range of load and generation conditions in accordance with reasonable and prudent operating conditions.

Chargeable Capacity: capacity that the distributor may charge for but that may not be the actual installed capacity at the relevant ICP. TLC measures Chargeable Capacity as the highest half hour load during the past 31 December to 31 December period.

Consumption pattern: the shape of consumption in an accumulation of half hour periods

Distributed generation: equipment used, or proposed to be used, for generating electricity that –

a) Is connected, or proposed to be connected, to a distribution network, or to a customer installation that is connected to a distribution network; and
b) Is capable of injecting electricity into that distribution network.

Grid: means the system of transmission lines, substations and other works, including the HVDC link used to connect grid injection points and grid exit points to convey electricity throughout the North Island and South Island of New Zealand.

Grid Exit Point (GXP): any point of connection on the Grid-

a) at which electricity predominantly flows out of the Grid;

Half-hour metering: m metering that stores information relating to electricity consumption during half hour periods.

ICP: an installation control point being one of the following:

a) a point of connection at which a customer installation is connected to a network other than the grid
b) a point of connection between a network and an embedded network:
c) a point of connection between a network and a shared unmetered load

Interrogation: the extraction or manual reading of stored data from a metering installation.

kW: a kilowatt of electrical power

kWh: a kilowatt hour of electrical energy

Profile: a fixed or variable electricity consumption pattern assigned to a particular group of meter registers or unmetered loads

Raw Meter Data: the records and data used to determine meter readings, being information obtained directly from the interrogation of a metering installation

Concepts and terms that are used procedurally within the The Lines Company.

Allowable Revenue: Maximum Allowable revenue as determined by the calculation set by the Commerce Commission.

$$Maximum\ allowable\ revenue = P_t \times Q_{t-2} - K_t$$

(t = year, P = price, Q = quantity (kW load),K = Pass Through Costs)

Community of Interest: A community of people within TLC network that share a common interest with regard to a particular local network . Opt Back: The ability of customers with a Time of Use (TOU) meter to choose either the kW load calculated under the relevant profile or the kW load as measured from the data provided by a TOU meter.

Distribution: the distribution of electricity within a network such as the Lines Company. Generally by 33kV, 11kV and 440 V lines.

Holiday Home: a home other than a Principal Place of Residence.

ICP: An Installation Connection Point

kW Load:

Low User: A Principal Place of Residence that uses less kW Load than that used by the average domestic consumer on The Lines Company network consuming 8000 kWhs a year.

Prompt Payment Discount: the discount given on the total lines charge if the bill is paid by due date.

Principal Place of Residence: a dwelling house, apartment or other similar place of residence where the person generally sleeps and eats. The following factors can be taken into account in determining whether or not a residence qualifies as a principal place of residence:

- the length of time the person has lived in the residence;
- the address to which a person's mail is sent;
- the place of residence of a person's family;
- whether or not a person's belongings are kept at the residence;
- the person's address on the electoral roll;
- the person's intention in occupying the residence;

Standard meter: an electro-mechanical meter only capable of measuring electricity consumption. This is similar to an odometer in a car. No historical data is retained.

Time of Use (ToU)meter : Half Hour metering that stores Raw Meter Data for a period of at least 12 months.

Transition Period: the interim period between the present and the full rollout of Load Meters.

Transmission: the transmission of electricity along the Grid.

Context - The Lines Company

In 1986 the New Zealand Government introduced a series of reforms that led to the dissolution of Electricity Supply Authorities (ESA). These reforms initiated the separation of the Electricity Industry into generation, distribution and retail. The King Country Power Board and the Waitomo Power Board worked together to create two new entities; The Lines Company (TLC) and King Country Energy.

In industry terms, The Lines Company is a distribution company and King Country Energy is a retailer. TLC is owned by two consumer trusts; King Country Electric Power Trust (10% shareholding) and Waitomo Energy Servicers Customer Trust (90% shareholding). TLC distributes electricity to a geographical area that has difficult access, low population density and a significant proportion of seasonal demand. Table 1 shows a selection of statistics in an industry benchmarking study carried out by Price Waterhouse Cooper in 2011.

	Total Circuit Length km	Rural &Rugged Terrain % of Circuit Length	Connection Points ICPs	Connection Point Density ICP/km	Demand Density kW/km
TLC	5,001	39	24,474	5	13
median	3,505	-	28,170	9	28
minimum	255	-	4,471	3	12
maximum	29,920	39	531,185	36	129

Table 1: 2011 Industry Statistics

Ref: "Electricity Line Business – 2011 Information Disclosure Compendium" PWC,Oct 2011

In 2005 The Lines Company started direct billing. This meant that customers in the TLC network no longer had their distribution charges bundled together with their retail charges. Each customer was able to clearly see the cost of distribution. Under direct billing TLC is able to ensure that customers who live in a region with a common Community of Interest are charged for the cost of service and distribution to that area, and subsidies between Communities of Interest are clearly identified. with a view to recovery by The Lines Company of the full economic costs of providing the distribution services.

In 2007 kW Load was identified as the optimal method of charging for a distribution service, when compared to kWhs. The difference is that kW load is a measurement of power, whereas kWh is a measurement of energy. kW load is a period in time whereas kWh is the sum of those points. Measuring and charging on the basis of kW load is a method of matching the contribution that the load of an ICP makes to the peak load on the local networks. The variable charge is weighted so that a message is sent to encourage the customer to shift their peak load. This action is identified in economic terms as demand-side management. The financial reward to the customer for adjusting their peak load is a decrease in charge and the financial benefit to TLC is the potential deferment of the costs of supply. A variable kW load charge is also used by Transpower owner of the Grid as part of its pricing methodology. TLC has devoted considerable resources to the message that it charges on load. Peak load growth is reducing and loads are flattening as customers are commencing to actively manage their kW load and in turn their overall charge, .

Since **2009** TLC has been actively promoting the installation of Time-of-Use meters. As these and future Load Meters are installed the need to use Profiles will reduce. About 8 % of TLC customers currently have a TOU meter installed.

In **2011** TLC contracted Sapere to review its pricing methodology and measurement of kW Load. kW Load at that stage was measured as the highest single 3 hour (1x3) period coincident with a load control period on the local network. The three hour period allowed for diversity between loads to be captured, whereas it was recognised that measurement over single half hours did not. The three hour period had been chosen as the result it produced for an dwelling closely matched the actual load that was incorporated into network design. The Sapere Report supported the methodology however suggested a number of changes including a rationalisation of the measurement. The report suggested increasing the number of measurement periods and shortening the period that the measurement was based on.

In order to retain the benefit of capturing diversity between loads and the linkage to the actual load levels seen in load flows the average of the six highest two hour peaks (6x2) of an ICP co-incident with load control periods on the local network was recommended. The new measurement had the benefits of:

- removing the possibility of consumers being disadvantaged by a single rogue peak
- increasing the importance of the regular by shorter periods of morning load control.

The recommendations were taken through an extensive public submission and consultation process and have been applied in 2012.

A summary of the submissions to the Review, their consideration by the Directors of The Lines Company and the resultant report is available on the TLC website. The four other major conclusions from the submissions were:

- More profiles should be adopted to ensure equity between those on TOU meters and those on profiles
- Holiday home minima should be increased as recommended by Sapere
- Where a relevant profile existed a customer on a TOU meter should be able to Opt Back to the profile once.
- There was little support to rebalance the revenue recovered between the Capacity based network charge and the kW Load charge.

In **2012** TLC continues to focus on its customers and how to provide for their long term benefit. he TLC is continuing to identify the measurement of kW load as a significant part of its pricing methodology. The recommended measurement methods (6x2) have been adopted and processes are being developed to ensure that within technological limitations charges are as equitable as possible and presented in as transparent manner as possible. A Transition Period has been introduced that will ensure that inequities resulting from the different meter types are minimised. This allows the majority of TOU customers the option of switching back to the relevant profile if it is to their advantage. In the longer term investment is continuing to be made in developing a supply of Load Meters that will work within the geographical constraints of the network regions.

Context - Our customers

Our Customers

The Lines Company is owned by two customer trusts: King Country Electric Power Trust, and Waitomo Energy Services Customer Trust. These trusts are elected by the customers of TLC and appoint a Board of Directors to govern the business operations of The Lines Company.

Families and individuals whose Principal Place of Residence is within The Lines Company network, make up the single largest group of customers. The second highest group of customers are Holiday Home owners and occupiers. Although TLC is obliged by regulation to recover the full economic costs of service provision, it is also obliged by regulation to provide subsidy to residential Low Users and rural communities.

The Lines Company strives to provide quality community support. This support is in the form of education about our charging methods and load management, customer surveys, scholarships and community sponsorship.

Context- The Regulators

The Regulators; Commerce Commission (Comcom) and the Electricity Authority (EA) regulate pricing and quality of supply of electricity distribution for 'the long-term benefit of consumers'. A distribution network is a natural monopoly. A natural monopoly does not operate in an efficient competitive market as the demand side of the equation (consumer) is not able to participate fully by exercising substitution.

"In these markets, the Commission may need to regulate the price and quality of goods and services for the long-term benefit of consumers." (ComCom website, March 2012)

As a regulated industry participant, The Lines Company is obliged under statute, The Commerce Act 1986, to publically disclose financial and service information on an annual basis. Furthermore The Lines Company revenue is regulated and a maximum allowable revenue threshold set. Should TLC breach any of its statutory or regulatory duties there are considerable financial penalties.

"Promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long- term benefit of consumers." (S15, Electricity Act 2010)

This second quote is the statutory objective of the Electricity Authority. The EA was established in 2010 to replace the Electricity Commission. The EA's main vehicle of regulation is the Electricity Participation Code; this code covers all major electricity industry participants. TLC is required to follow EA Pricing Principles when setting a pricing methodology. Refer to the Appendices for a summary of TLC alignment to these Pricing Principles. The Commere Commission provides Information Disclosure Guidelines. These dictate the information that must be included in the pricing methodology. Refer to the appendices for a summary of TLC alignment to the Information Disclosure Guidelines.

The primary stakeholders of TLC; customer owners, employees and regulators share a common strategic goal: the long-term benefit of the consumer. This Pricing Methodology document sits alongside the Asset Management Plan in providing organisational and procedural support for the provision of "pricing structures that promote energy efficiency , the reduction of network energy demand and better asset utilisation" (p17, 2011 TLC Asset Management Plan)

Methodology – kW load

The Lines Company prices on the uncontrolled kW load of a customer during periods of peak network demand (network constraint). The network must be able to operate during these periods of peak demand. By measuring uncontrolled demand during these periods TLC is able to plan for both revenue and expenditure. The measurement of consumption (kWh) does not give information about peak/maximum demand and cannot be used to determine the requirement of the network.

Uncontrolled load is load that TLC is unable to control. Ripple relays are a load control device that allows control on parts of a customers load. Generally the hot water cylinder will be on the load control circuit. During periods of network constraint these relays will be activated and a portion of potential load will be under the control of the network operator. This is why TLC only measures the load when load controlling.

For customers on Standard Meters if the controlled usage is separately metered the profile is based on the uncontrolled usage only. Where both controlled and uncontrolled usage is metered through the same meter, or where metered controlled load is limited and some may coincide with a general load control period then load is apportioned.

TLC is not alone in recognising kW load as the main driver of cost for an electricity distribution network. As already noted, Transpower also uses kW load as a measurement of demand. The peak maximum demand on a network determines the supply capacity that network must have available. In utilities such as electricity distribution demand invariably outpaces supply and it is the business of TLC to identify future demand growth and plan both capital and operational expenditure to manage that growth. All electricity networks have periods of peak demand, whether these periods of peak demand coincide with periods of network constraint in the short-term depends on the capacity of the networks.

In establishing kW load for an ICP it is important to first identify the meter at the installation.

TOU meters provide half hour consumption data. For kW load to be determined this data needs to be validated and matched to the relevant periods of network load control. However if the meter is a Standard meter and only able to provide consumption data from actual meter reads it is necessary to first establish consumption for a 92 day period and then correlate this against a formula developed using TOU sample data sets. This then provides the calculated kW load.

Time of Use meter

Standard Use Customers:

> Prior to 2012 TLC took the single highest three hour peak of an ICP coincidental to a three hour period of load controlling. During 2010 and 2011, TLC employed Sapere Group to review this method of data capture and methodology. On Sapere Group’s recommendation and as a result of public consultation TLC determined in 2012 to adopt a different method of measurement. The kW load of an ICP is now established by identifying the average of the six highest two hour peaks coincidental to load network load control periods.

Major Use Customers:

> As these customers have a singular influence on the local network it is not necessary to identify the coincidental average of the six highest two hour peaks (6x2). The data is either “demand coincidental

with 100 highest Transpower peaks “ or the average of the six highest two hour peaks at the installation, independent of network constraints.

Data Rules:

A set of rules have been established, based on work from an independent statistical consultant, to provide transparency and consistency to the TOU data collection and load measurement process. These are summarised into 7 stages:

1. Collect data. Handheld meter readers download the data from each TOU meter.
2. Establish calendar period for data collection. These dates apply to ICP data and network data. For the 2012 period TLC used TOU data from June through September, and Dairy shed data from September through December.
3. Validate ICP data. For the relevant period ensure that the ICP data meets a set of rules that ensure the final data has no inconsistencies. These may include daylight saving adjustments.
4. Collate regional load control periods from network data. As this data is from the SCADA system (used to control the network) it is seen as the true data.
5. Match ICP data to control periods.
6. Identify the highest six two hour periods of coincidental demand.
7. Average the 6x2 to provide kW load of ICP

Adjustment to TOU Data

The data on which the Profiles are determined is largely data from meters measuring uncontrolled electricity usage. This data is not contaminated by controlled load.

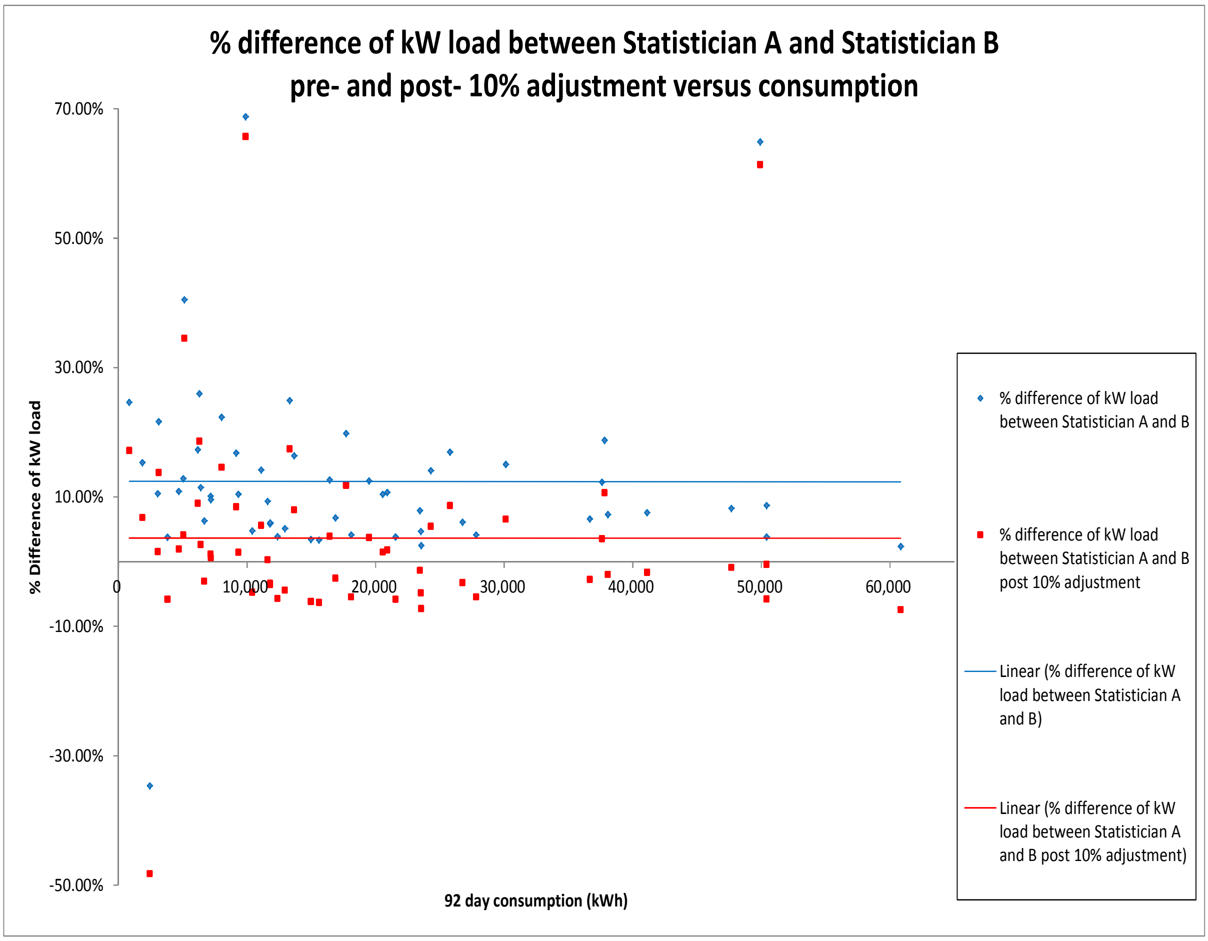
Where a Time of Use meter is present it may however be metering both controlled and uncontrolled usage. As load control commencement and end times rarely coincide with the beginning or end of half hour periods then the data for some of the period of load control is contaminated and must be clipped. This is likely to result in the kW load from the normal TOU customers being lower than that used for profile setting, which if left unaltered would mean that loads would rise as TOU meters where replaced with Load Meters. The difference this year is significant due to the way that data is clipped. That is, removing the “Controlled Data from the “Uncontrolled Data”, as the calculation is based on uncontrolled data only.

The profiles are calculated by a consultant independent of the one used to calculate the ToU load.

For consistency we have used the same clipping method as in previous years for the ToU load calculation and then adjusted the data to take into account the difference between this method and that used to produce the profiles. The result is an upward adjustment to the TOU meter data of 10%.

This adjustment is based on the difference on the slope of the graphs that each method produces, based on individual customer data points and using regression analysis producing a flat line of difference of 10.6%. We have applied a flat rate increase of 10% to the calculation based on this.

Where a customer’s meter has been used for profile setting and also had its load calculated using standard clipping the load allocated to the customer is the lower of the load as measured for the profile and the adjusted load after clipping.



Standard meter

The meter is read by the retailer and downloaded into the Gentrack billing system at TLC. This data is ideally read each month however as it is a manual system it may mean that consumption spans a longer period. The consumption data is established for a 92 day period that corresponds to the relevant periods of constraint on the network. This 92 day consumption (kWh) is the independent variable in a formula that has been developed using sample TOU data in order to provide the equivalent kW load for that installation.

In 2007 when kW load charging was first introduced a control set of TOU meters was installed. Since that time these are the meters that have provided the half hour data that has been used to establish the conversion formula. As more and more TOU meters have been installed TLC has been able to identify different usage patterns for Standard Use customers. As these patterns become clear TLC plans to utilise the data and develop further profiles (formulae) which will then be used to derive the kW load for similar users without TOU meters. The Dairy profile which was introduced in 2008 is an example of this. In the methodology published 2008 this intention was laid out;

“ Demand meters are being fitted in a range of businesses. The data from these plus existing half hour meters is being analysed to produce assessment formulas.” (P4, The Lines Company Line Charges Methodology, effective at 1 April 2008)

Customer Profiles

Customer profiles are based on similar usage patterns, from statistically valid data sets.

Three profiles have always existed, though only Standard and Dairy had separate profile formulae . In 2012 the third customer profile formula has been established for Temporary Accommodation.

1. Standard
   The Standard formula is for Principle Places of Residence and other end users who are not designated under either of the other two customer profiles. It is based on the assumption that as kWh consumption increases load levels do not increase proportionally.

2. Dairy Profile
   The Dairy profile exists as dairy milking sheds do not peak over winter, and instead contribute to local network peaks during August to December.

3. Temporary Accommodation
   This year, based on the review of data and the customer consultation process we have established a third profile, Temporary Accommodation. This profile includes holiday homes, where at the lower end consumption does not correlate to load, and those installations where the load level is more likely to increase in proportion to consumption as the increase in consumption, at least in part, simply reflects a greater number of accommodation rooms or guests.

   This profile includes holiday homes, accommodation businesses, ski lodges, and other similar establishments.

Load level

Load levels are measured by either a TOU meter, where such a meter is installed, or through calculated by application of a Profile formula.

Where a TOU meter is fitted at a customer's installation then the load level is calculated by:

(a) For installations above 100 kVA – by taking the coincidental average of the six highest two hour peaks (6x2). It is assumed that such installations are large enough that their peak usage influences the local network requirements.

(b) For installations 100 kVA and below – by taking the coincidental average of the six highest two hour peaks (6x2) when we are load controlling the water heating load of the local customers.

Where a standard meter is fitted the load is calculated using formulae derived using rules and processes developed by an independent statistician to give the best-fit correlation between peak load and overall consumption using a sample data set of TOU meters. In 2012 the peak demand of the sample set is derived using the 6x2 measurement.

Load Control times vs. Set times

We are interested in establishing an installation's actual or potential contribution to the network's demand levels at peak times. It is recognised that establishing set peak times in pricing options does not necessarily work as customers shift their load in accordance with the pricing signal, and that can cause peaks to be experienced outside the set times. The only way to avoid this is to set very wide time bands, which sends weak signals to customers.

We only operate water heating load control when we, or Transpower, are likely to experience a peak. If we only measure the demand when the water heating load control is operating then we are giving customers an incentive:

- To increase the load controlled on the water-heating channel; as that load will be switched off by us when we are measuring, then the load will not contribute to the demand level.
- To identify when we are load controlling and either automatically or voluntarily switch off load at those times.

The second option opens the market to innovation through third parties providing devices that signal our use of load control.

Interval Period

Our aim was to establish a measurement period that could apply equally to commercial, industrial and domestic loads.

Industrial loads tend to be flat. The same figure is therefore likely to be imposed on the system irrespective of the time interval selected. Domestic loads, however, are very peaky with installation peaks set over short periods of time, with the load then declining quite rapidly. However, not all domestics peak at the same time; there is a large degree of diversity among domestic installations.

An average domestic contribution to demand of around 2.0 to 2.5 kW was considered reasonable. This judgement was based on:

- Advice we received from Delta on studies it had undertaken.
- Measurement of substation demand, where the substation was supplying almost solely domestic load.
- The capacity levels used by engineers in substation and subdivision design.

A sample of domestic installations was metered with half hour meters over the 2006 winter. Uncontrolled usage only was measured. From that exercise a 2½-hour period was initially chosen. However the quality of data over the 2007 winter was much higher and therefore a 3 hour period has been adopted for the 2008 and subsequent demands.

Subsequent comparisons of demand levels calculated by using figures from the formula used with annual consumptions in kWhrs for houses with electric water heating has shown that the average house with an annual consumption of 8000 kWhrs has a demand of 2.2 kWs. This is in line with the above and this figure has been used for the Low User consumers since 29 March 2010.

Calculation determination

Apart from the exception below, the calculations are undertaken by using formulas derived by a statistics consultant to give the best correlation between uncontrolled energy usage and kW Load.

Load control periods occur during a time of peak load on the regional network.

For customers who do not have their uncontrolled consumption separately metered, or where the "controlled consumption" is limited in some way, the uncontrolled portion of the load has been assessed as follows:

- Composite controlled/uncontrolled – Waitomo, Otorohanga, Whakamaru and Arohena 76% of the consumption (based on the assumption that as the majority of customers have their uncontrolled usage separately metered, those customers still on the composite rate are likely to have a higher than average proportion of uncontrolled consumption).
- Composite controlled/uncontrolled – Taumarunui, Turangi, National Park and Ohakune 65% of consumption (a significantly lower ratio of customers have their uncontrolled usage separately metered. This provides a small incentive for the average customer to request separate metering).
- Limited Off peak – 55% of consumption.
- Night – 0%.

1. Standard Profile

Actual meter readings between 1 June and 30 September are used. Where there is only one meter reading available during that period the readings from May through October may be used. If no meter readings within this period are available then, on some very rare occasions, meter readings outside of these months are used, or the load will remain unchanged.

The daily consumption is calculated using the actual readings and extending or narrowed to 92 days as required.

The total "uncontrolled consumption" as calculated with the above percentages is used in the formula.

This formula is of two parts reflecting the following:

1. Where the consumption is less than 1,189 kWh and equivalent to 2.2 kw the Low User Regulations apply. The application of a power formula reflects the extremely low loads of this group.
2. Above 2.2kW load, a linear calculation is used.

Standard Profile

$kW\ load = 0.07067\ \times (92\ day\ consumption)^{0.4931}$ (less than 750 kWh);

$kW\ load = 0.000792049 \times (92\ day\ consumption) + 1.258$ (equal to or greater than 750 kWh).

2. Dairy Profile

Actual meter readings between 1 September and 30 December are used. Where there is only one meter reading available during that period the readings from August through January may be used.

If no meter readings within this period are available then, on some very rare occasions, meter readings outside of these months are used, or the load will remain unchanged.

The daily consumption is calculated using the actual readings and extending or narrowed to 92 days as required.

The total "uncontrolled consumption" as calculated with the above percentages is used in the formula.

The calculated formula is as follows:

Dairy Profile
$kW\ load = 0.00091 \times (92\ day\ consumption) + 4.02$

3. Temporary Accommodation

Actual meter readings between 1 June and 30 September are used. Where there is only one meter reading available during that period the readings from May through October may be used. If no meter readings within this period are available then, on some very rare occasions, meter readings outside of these months were used, or the load will remain unchanged.

The daily consumption is calculated using the actual readings and extending or narrowed to 92 days as required.

The total "uncontrolled consumption" as calculated with the above percentages.
This formula is of three parts reflecting the following:

1. Where the profile formula calculation under the Standard profile calculation would result in the minimum as described below, this is used. This part of the formula is used up to 2.5kW. For Holiday Homes a minimum of 2.2 kW applies in areas other then Ohakune where a minimum of 2.5 kW applies.

2 Between 2.5kW and 7kW a linear calculation is used.

3. Above 7kW load, the load reflects the capacity, i.e. if capacity was to double so would the load, which is what is observed in the data analysis.

Temporary Accommodation Formula 2012
$kW\ load = 0.07067 \times (92\ day\ consumption)^{0.4931}$ (for consumption less than 750 kWh);

$kW\ load = 0.000792049 \times \left(92\ day\ consumption\right) + 1.258$ (for consumption greater than or equal to 750 and less than 1,568 kWh);

$kW\ load = 0.004873 \times \left(92\ day\ consumption\right) - 5.142$ (for consumption greater than or equal 1,568 and less than 2,491 kWh);

$kW\ load = 0.02269 \times (92\ consumption)^{0.7329}$ (for consumption greater than or equal to 2,491 kWh).

As holiday homes are used intermittently, demands cannot be adequately calculated from consumption data. The networks supplying the areas where these are sited, however, generally are built to supply the seasonal holiday peak. The minimum load level for a Holiday Home may be increased above that produced by the Temporary Accommodation where Higher fuse sizes, the presence of uncontrolled water heating or submaining, lead to an inference of a higher demand level.

The minimum level for holiday homes is based on the average TOU load of TOU meters in holiday homes using less consumption than the average house.

If a holiday home is only occupied out-of-season, or has a very small or well managed load, then it would be beneficial for the customer to have a TOU meter fitted.

<u>Load Control Periods</u>

The number of load control periods used to assess load levels for calculation of the profile formula is a critical part of the assessment. The number of periods has an S-Curve graph, i.e. a minimum number of periods beyond which the result of the low number of load control periods will produce the same load level result due to the natural load that a customer will use. For example, a house with a refrigerator and other similar appliances that operate continuously will have a natural load that these appliances use regardless of other uses the householder may use.

There is a maximum number of load control periods above which the load level will be materially the same. This is because there is a natural load that a premise has.

Our assessment based on historical data is that the lowest number of load control periods that give the right load settings is approximately 90.

Unfortunately, during the 2011 calendar year, the number of load control periods in some regions was less than 50. This resulted in a statistical aberration in the Hangatiki region, where the sample data set for establishing the Standard profile formula.

Due to this we have used the previous year's (2011) Standard profile formula to ensure that no customer is adversely affected by this anomaly The 2011 year was a mild winter. Overall consumption between the two years is substantially the same.

It is important to note that the calculation of an individual customer's load level using the formula is based on that customer's electricity consumption over the assessment period and this is not impacted by the number of load control periods.

Therefore a customer who is on the Standard profile will have their load level calculated consistently with the prior year and is therefore not adversely affected.

For those customers who use a TOU meter, their load level is calculated using the data from the meter and will therefore be consistent with their usage patterns.

In summary, this year for the Standard profile formula we have used the current year's consumption data and the previous year's formula, adjusted as set out below for Opt-back.

Opt-Back

As part of the transition to advanced meters over the next few years we are using a transition process that will enable customers to have TOU meters installed and maintain the lower of the load from the TOU or calculated by the relevant profile formula. During this period TLC will continue to install TOU meters as requested and will continue to use the data gathered from these meters to improve the management of kW load Methodology

This will be available for a minimum of two years and customers will have the option of either moving back to the formula or keeping with their TOU load. Once a customer has decided to no longer have the opt-back option, that is to stay with their TOU load, they cannot opt back to the formula the following year.

This will give time for customers to engage in load reducing strategies should they so desire and TLC will be helping customers with these strategies should they require assistance.

We have automatically placed all customers with a TOU meter on the Opt-back where this would give them a a lower load level.

We have written to each customer who has a TOU meter setting out their individual options and advising them that we have set their load at the lower of the two, and advising them they can alter this if desired

This Opt-back has had an impact on the calculation of the profile formula. Each profile formula has been adjusted to keep load neutrality. That is the reduction in the load levels arising from the Opt-backs has been accounted for by a percentage increase in the relevant formula as follows:

Standard Formula	1.61%
Dairy Formula	0.97%
Temporary Accommodation Formula	4.63%

As we move forward until Load Meters are universally installed in any area and Profiles abandoned then wee can expect those customers with loads less than the Profile to opt out of the profile and the Profiles to be adjusted to reflect the average of the customers on the respective Profile.

kW Load recalculations

kW Loads can only be recalculated if subsequent meter readings show that there was an error in the readings used for the original calculation. If there is such an error then the amended kW Load level shall take place with effect from 1 April.

Load Resets

Load resets during the chargeable year are at the discretion of TLC. TLC's policy with regard to resets is on its website.

Methodology - Capacity

TLC distributes electricity. It builds and maintains its network to a forecast maximum load or capacity requirement.

An ICP can either have a notional level of chargeable capacity or an catual level as measured by a TOU meter over the last relevant measurement period.

Where a TOU meter is not fitted a notional level of kVA is calculated either by reference to the level sought on the Connection Application when the installation was established or by historical assessment. In general the average house will have a Chargeable capacity of 5 kVA. Larger houses may have a Chargeable capacity of 7 kVA.

Taking this back to household level; the chargeable capacity must be greater than the peak kW load. For most installations below 100kva the chargeable capacity has proven to be approximately two times the peak demand.

Assets

enable The Lines Company to distribute electricity to its customers. A challenge TLC is to manage the assets of the network in a manner that balances both service level requirements and the revenue thresholds whilst ensuring delivery at the levels required by the Commerce Commission quality thresholds.

The service level requirements are determined by historical measurement of outage length and frequency. These measurements, System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) must be publically disclosed andthe Commerce Commission has thresholds set based on the historical data. If The Lines Company exceeds these targets it is held in breach and may be fined by the Commerce Commission.

Poorly maintained assets are more liable to outages and thus could expose TLC to breach situations. To replace and maintain assets requires operational and capital expenditure, to fund this expenditure TLC needs to determine a level of revenue yet still ensure this revenue does not exceed the revenue threshold set by the Commerce Commission .

Assets are identified as common assets and dedicated assets. Dedicated Assets include transformers, lines supplying single customers, relays and meters. Large value Dedicated Assets are more general in rural low density areas, although some, like streetlight circuits, are also found in urban areas.

Charging for Dedicated Assets is in line with the Electricity Authority pricing principles of recovery of full economic costs. Streetlights and dedicated lines are other examples of Dedicated Asset charges.

For common assets refer to the attached Tables for the cost of asset maintenance and the value related costs of assets as shown by regions.

Price - Variable charge

The Variable Charge uses kW load as a multiplier. Customer feedback and technology constraints mean that the multiplier is reset once a year. Customers receive a monthly invoice that does not vary throughout the year and allows simpler cash management. Technology constraints mean that real time data is not available and instead must be applied historically. Analysis has shown however that load levels between years are unlikely to significantly vary unless steps are taken to either increase or decrease natural load at the installation e.g. increasing insulation, replacing energy inefficient appliances.

Once a kW load has been determined for an ICP, either using a profile or meter measurement, the sum of these loads will be run through a pricing model and then a tariff established. The pricing model uses the Cost Allocation methods already explained in the section on cost and quantified in the Cost Allocation tables in the appendix.

For Standard Use Customers there are two variable line charges that use kW load as the multiplier.

Transmission:

- This is a Pass Through charge. This recovers the connection and interconnection fee charged by Transpower, and avoided Transmission charges paid to Distributed Generators, for the local region, less interconnection charge charged to back to back customers (see below)the Major Users. As this is a Pass Through charge it is clearly identified on the tariff schedule. From 2012 the customer invoice separately identifies this charge.

kW load:

- As previously identified, the kW load charge returns approximately half of The Lines Company revenue. The tariff is appropriate to the cost allocation of the GXP region.

The Major Users also have two variable charges. Both are Pass Through charges and use the established kW load as the multiplier.

Transmission Connection Charge:

- The charge is determined by the regions total connection charge divided by the kW load of the same region. The kW load is used as a multiplier and billed monthly.

Transmission Peak Demand Charge:

- Uses the kW load multiplier and billed monthly. The demand charge is determined by dividing the regional combined interconnection charge Transpower and avoided Transmission charges from distributed generators, less the amount charged back to back customers, by the kW load of the same region.

- Back to back: Instead of kW load calculated using TLC control periods the customer may use a kW load multiplier calculated using the customers average half hour load coincidental with Transpower's chargeable peaks.

The **Fixed Charges** comprise of the following charges:

- Network charge
- Meter charge
- Control fee
- Dedicated Asset charge

Network Charge

The network charge is based upon the customer's Chargeable Capacity requirements as measured at the transformer, the point where the customer's demand integrates with the system.

Currently the network charge produces around 1/3 the revenue required from the combined network and demand charges. In the future this will be increased to ½ the revenue in non-constrained areas.

Capacity level

Capacity requirements are based on either the capacity, which we have been contracted to supply (normally being the higher of the level being taken or that stipulated on the Connection Application).

The capacity requirements are then banded into groups to which we assign a notional size. The diversified groups are as follows:

Capacity kVA	Notional kVA
1-3	2
4-6	5
7-9	8
10-11	10
12-15	13
16-20	18
21-30	25
>30	Diversified size

This grouping ensures that customers in similar circumstances receive similar charges.

Domestics are assessed at a minimum of 5 kVA.

Network charges vary between voltage levels (high/low) and location (suburban/rural).

- A low voltage charge is payable by a customer not paying a transformer charge, i.e. the charge covers the cost of shared transformers and the associated low voltage network as well as the portion of high voltage network costs covered by the high voltage charge.
- A high voltage charge is payable where the customer is paying a separate transformer charge.
- A high density charge for installations where load density is greater than or equal to 50kVA/km. Load density is measured by summing the load between the customer's point of

connection and the start of the feeder and dividing that sum by the distance between the point of connection and the start of the feeder.
- A low density charge where density is less than 50kVA/km.

Low usage option

To comply with legislation a low usage option has been introduced for Principal Places of Residence. The fixed charge has been set at less than the regulated level to ensure that, when added to the relay charge, this does not produce a total charge in excess of that permitted by regulation. The variable charge is set to recover the same amount as the normal option if the customer has a demand of 2.2 kW.

All customers who would benefit from this option (generally those on the low voltage network charge), and who are not in an exempt area, are moved to the option.

The residual cost of this group is recovered by adjusting the standard demand.

Discussion

Having part of our costs covered by a capacity based charge has two benefits:

1. Installations that are not using the network over peak periods still contribute something towards the network cost, i.e. all installations contribute something towards network costs.
2. The variability in the total lines bill from one year to another due to changes in demand levels is dampened. This enables customers to experience most but not all of the extra cost due to an increase in demand and modify behaviour if the increased cost is considered undesirable.

For industrials above 100 kVA the network charge covers all network costs not covered by charges for dedicated assets and the customer service charge, i.e. the load based charge covers Transmission costs only. This is based on the assumption that the individual capacity requirements of these customers are of such a size that they influence the design of the local network, and therefore the investment is incurred irrespective of whether it is used.

Meter Charge

Meter charges are based on the type of meter installed. Standard meters and TOU meters are charged at the same rate. Current Transformer (CT) meters are charged according to size. These are mainly installed at installations where there are high kVA loads.

Control Fee

The control fee covers the cost of a dedicated relay where this is provided. The level of this fee reflects the historic value of these assets. As Load Meters are installed then the relay will be incorporated in the meter and this fee will be incorporated into the Meter Fee.

Dedicated Asset Charge

Dedicated Transformer:

A dedicated transformer charge is applied where there are three or less installations attached and using that transformer.

As the Dedicated transformer charge should fully recover costs over the life of the transformer, the value allocated has reference to replacement asset value, site establishment costs and maintenance costs.

Dedicated Lines:

A dedicated line fee will be charged where the line is specifically for the use of a customer, or is sized to meet the requirements of a customer.

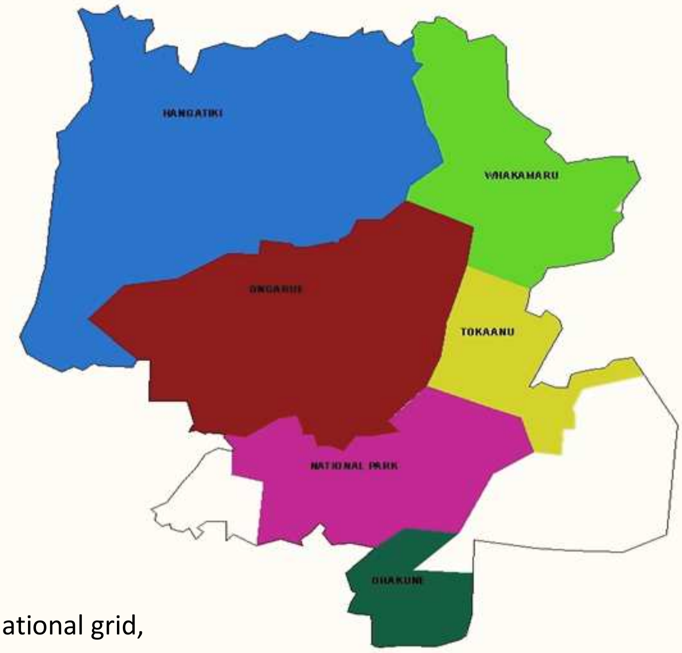
As the Dedicated Lines charge should fully recover costs over the life of the line the value allocated has reference to replacement asset value, site establishment costs and maintenance costs.

Cost

6 local charging regions have been established based around perceived Communities of Interest. These coincide with 5 GXPs , Ohakune, Ongarue, Hangatiki, National Park and Tokaanu, and Whakamaru, which is connected to a number of generators.

Amalgamation of charging regions, or creation of new regions, is dependent upon the view of our shareholder Trusts who represent these communities.

Each region has a different regional load profile asset value, ICP density and consequently cost per kW load or kVA of capacity.. Subsequently each region has a set of variable and fixed tariffs. For standard line charges there are two divisions within each region. The voltage of the lines supplying the point of supply; high voltage and low voltage, plus the capacity requirements of the immediate region (close to the ICP). These capacity requirements have two levels: greater than or equal to 50 kVA per km – this is referred to as high density and generally reflects urban areas. The second level of density is less than 50 kVA per km and is generally associated with rural areas. Tariffs differ according to the voltage and density of the ICP zone. The rationale for these different tariffs is cost allocation; a region close to the national grid, with relatively young assets, a large urban population and some industry will have a lower tariff. Conversely, a region a long way from the national grid, with mature assets, low population density and no significant users, will have a higher tariff.



Within the regions there are customers that are not allocated the full cost of recovery. These subsidies are acknowledged in the first section of the Electricity Authority Pricing Principles. The Low User Fixed Charge tariff is outlined in the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulation 2004. The stated intention is to provide a low fixed charge for consumers with less than average consumption in their primary place of residence. The tariff structure section will identify the processes used to identify and charge according to the regulations. A secondary area of cost subsidy is the high density/low density split. Both customer and industry opinion support a degree of continued cross subsidy, partly in recognition of price shock given the total removal of the subsidy (refer to S113,5 Electricity Industry Act 2010) and partly due to the cultural significance of rural communities in networks such as The Lines Company. However the rural community also recognises that our urban centres have very low socio-economic decile levels and that there is a limit on the level of subsidy that the urban communities can afford.

Transmission is the term used to denote the delivery of electricity from generators to distributors via the National Grid. The National Grid has 25,000 towers, 16,450 poles and 12,000 km of line. (Transpower Asset Management Plan 2010). Transpower is charged with operating the National Grid and is subject to similar regulatory disclosures as Electricity Distributors. As already noted Transpower has a similar pricing methodology to The Lines Company.

TLC payments to Transpower are made up of fixed (connection) charges and variable (interconnection)charges. There are also transmission payments to generators within the network that allow TLC to avoid extra Transpower interconnection charges.

These transmission charges – Transpower and Distributed Generation, are referred to as Pass Through costs and are referred to in the Commerce Commission regulations. The 2012 tariff schedule has separated these charges and this separation now appears in the bill format. In order to calculate the allowable revenue these costs are deducted:

$$Maximum\ allowable\ revenue = P_t \times Q_{t-2} - K_t$$

where K = pass-through costs.

To establish the monthly and annual kW load pass through charges to our customers:

- Transpower Connection charge divided by the sum of kW load for the region
- Interconnection charge (Transpower plus Generators) less maximum demand charge to Back to Back customers, divided by the sum of kW load for the region (excluding the load of Back to Back customers).

The tables in the appendices show this calculation.

Maintenance of the common assets in 2011 represented approximately 13% of total regulated line costs. These costs are shown in the appendix tables, initially as a portion of total cost, and thereafter broken down into the regional cost/revenue tables. Each regional table identifies the maintenance cost by allocation to contracted customers with dedicated lines, customers on 33kV, and 11 kV lines and those high and low density zones for 400V supply.

Trees are a primary cause of outages, both planned and unplanned. TLC has dedicated significant resources to consumer education and preventative maintenance in order to lessen the impact of tree damage during storm and high wind events. However as the photo on the next page shows, with 5,000 km of line through mainly rural areas trees are likely to remain a major contributor to outage costs (faults) and system maintenance.

Customer related costs in 2011 were approximately $35 per ICP/customer. These costs include levies paid to the regulators; Commerce Commission, Electricity Authority and to the Electricity and Gas Complaints Commission. Database costs; both internal and externally sourced are included and represent a third of the customer related cost. The largest contributing cost is administration. These costs are identified and allocated to both customers and regions in the appendix tables.

Asset Returns is a category that includes administration costs such as insurance and rates. These costs are included under asset returns because they relate to the costs of asset holding. The cost of depreciation is the second largest category and is according to Regulatory book Value (RBV). The single largest cost category is the cost of capital which has been calculated with reference to allowable revenue as calculated under ComCom input methodology. Refer to the appendix tables for the current year cost allocation by region.

Collection Costs are allocated across the regions using the total cost as the divisor. Refer to the Cost Table and Cost Allocation Tables in the appendix.

Customer groups

Because of the considerable range in regional Transpower charges, the difference in regional voltage transformations and accordingly the level of investment, and the lack of any single common community of interest binding all the districts we cover, customers have initially been grouped into regions supplied from single Transpower supply points. Where an area could be supplied from more than one Transpower supply point the customers in that area are grouped with those with whom they share the most in common. For example the Kuratau area on Lake Taupo is grouped with Turangi rather than Taumarunui.

Customers are then sub grouped a matrix as follows

Taking supply:

- From dedicated lines at 33 kV.
- 11 kV
- 400 V.

Density

- Urban.
- Rural.

When compared to historic power company areas, the regions of Taumarunui, Turangi, Ohakune and National Park comprise the old King Country area; the regions of Waitomo/Otorohanga and Whakamaru comprise the old Waitomo area.

Looking Forward

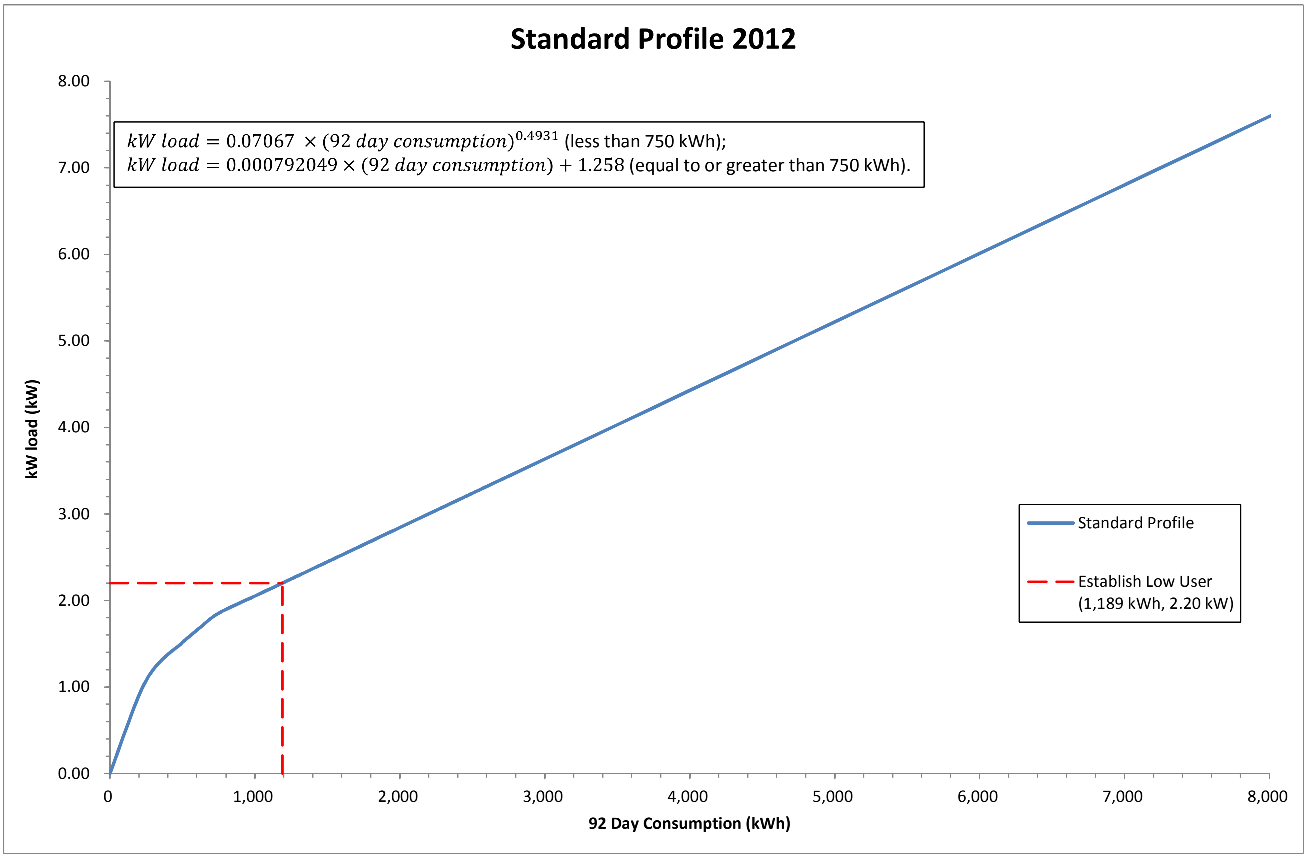
The electricity distribution industry is dependant on technology. The allocation of cost and development of pricing to facilitate this distribution is also dependant on technology. As metering technology advances TLC is able to manage the capture and processing of load data in a more accurate and timely manner. As network technology improves engineers are able to manage the conversion of gross power into lower voltages in a more efficient manner. Invariably technological improvement enables better measurement and therefore better management of assets. One of the challenges facing TLC is to develop robust processes that will provide the accuracy and timeliness of data that these advances deserve.

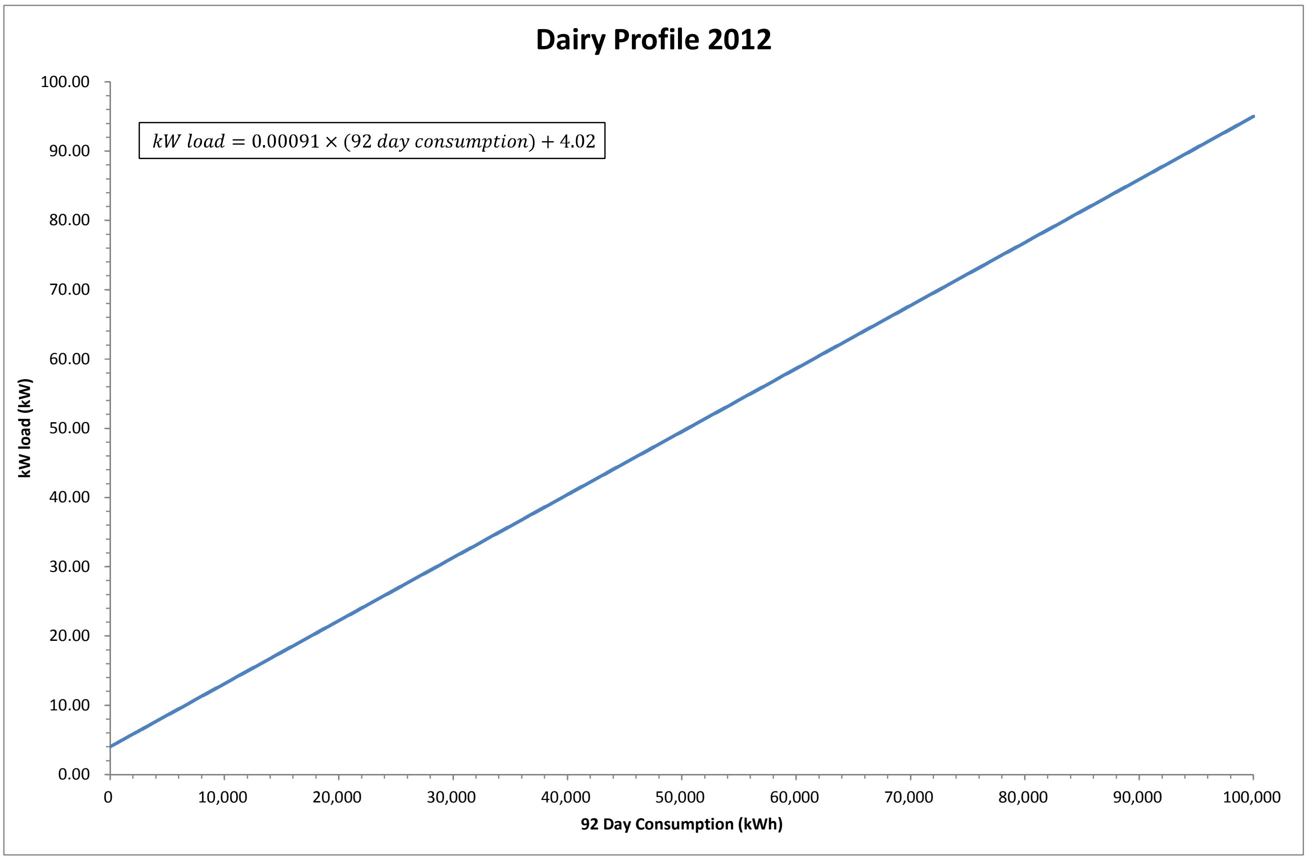
The Lines Company intends to facilitate a progressive rollout of Load Meters over the next 5 years. These meters will record consumption data, as do the existing meters, and in addition will record and measure kW Load data. They should also display kW load and enable load information In Home Displays with dynamic real time information. In the transition period TLC will be focussing on the procedural and operational systems that are necessary to provide equity and transparency..

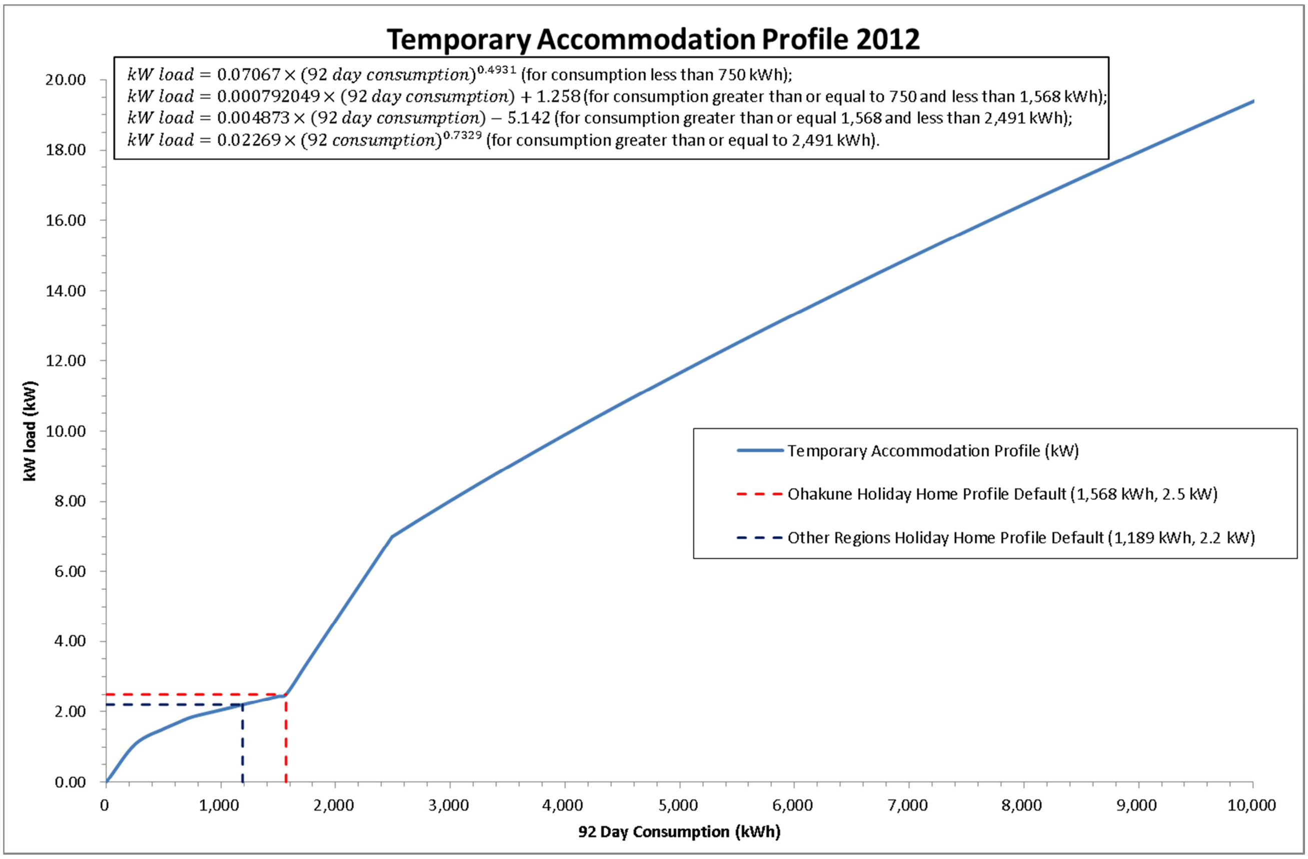
A service industry must always consider the quality and level of service it provides. TLC is continually looking to seek customer feedback on what level of service they require and at what price.

A: Formulae

kW load Profile Graphs and formulae




Dairy Profile 2012
$kW\ load = 0.00091 \times (92\ day\ consumption) + 4.02$
kW load (kW)
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0
10,000
20,000
30,000
40,000
50,000
60,000
70,000
80,000
90,000
100,000
92 Day Consumption (kWh)


Temporary Accommodation Profile 2012
$kW\ load = 0.07067 \times (92\ day\ consumption)^{0.4931}$ (for consumption less than 750 kWh);
$kW\ load = 0.000792049 \times (92\ day\ consumption) + 1.258$ (for consumption greater than or equal to 750 and less than 1,568 kWh);
$kW\ load = 0.004873 \times (92\ day\ consumption) - 5.142$ (for consumption greater than or equal 1,568 and less than 2,491 kWh);
$kW\ load = 0.02269 \times (92\ consumption)^{0.7329}$ (for consumption greater than or equal to 2,491 kWh).
Temporary Accommodation Profile (kW)
Ohakune Holiday Home Profile Default (1,568 kWh, 2.5 kW)
Other Regions Holiday Home Profile Default (1,189 kWh, 2.2 kW)
kW load (kW)
92 Day Consumption (kWh)
0.00
2.00
4.00
6.00
8.00
10.00
12.00
14.00
16.00
18.00
20.00
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000

B: Pricing Principles Alignment

Electricity Authority

Pricing Principles

(a)(i) “Prices are to signal the economic costs of service provision, by being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation.”

This is interpreted as that The Lines Company charges should reflect the cost of the ICP being serviced. The total charge to a customer should be equal to or greater than the cost of supplying the extra service. This total charge should be less than or equal to the Average total cost of service.

By charging in this manner TLC is able to operate as a financially viable business model. Decisions on operational and capital expenditure are made within standard business models.

The caveat on this is that existing and future subsidies must be applied. The rural subsidy is historical and its continued presence is ensured by statute and customer approval. The level of this subsidy will continue to decrease until the possible effect of price shock is removed. The presence of this subsidy in a network such as TLC will remain until significant regulatory changes are made that will financially aid EDB’s such as TLC with maintenance and renewal of their large rural networks.

The Low User Regulations (Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004) are the second subsidy that hinders TLCs full recovery of costs. This regulation charges lines businesses and retailers with assisting domestic users in reducing their consumption. Low Users are identified as households who consume less than the average of 8,000 kwhs. As TLC charges on kW load and not consumption, it has been necessary to determine a “point in time” where the average consumer consumption is equivalent to a kW load level. This is: 8,000 kWh = 2.2kW

TLC Low User Line Charges are structured so that:

- The fixed charge is less than 0.15cents per day.
- The total charge is less than the Standard Line Charge.

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

TLC is the only distribution business to invoice its customer directly. This means that TLC is able to influence customers demand responsiveness through pricing signals. For other Lines Businesses their charges are bundled by the retailer. TLC pricing methodology of charging on load, capacity and dedicated assets, informs the customer of the distribution costs of providing and maintaining network capacity at a level that meets the load requirements of the customer.

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

Long term investment in the network is determined by the informed behavior of customers who will adjust their load to the pricing signals and thus determine the long term capacity requirements of the regional networks.

Advancement in technology and the advent and successful marketing of powerful heating units such as heat pumps mean that the long term load on network capacity is likely to be increasing. The variable kW load charges combined with capacity charges and dedicated asset charges, as discussed above, signal to the customers the cost of future investment.

(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.

Demand responsiveness, price elasticity are terms used to represent the demand side of an economic pricing equation. Generally there would be sufficient competition in the market to ensure that both sides of the equation; demand and supply are able to act in an efficient manner. For the demand side (consumer) this means they are able to change their demand by substitution. An Electricity Distribution network is a Natural Monopoly, there is no competition and so the regulators step in to provide protection for a weak demand side. At TLC there is evidence that residential customers are presenting a reduction of peak load. Although not substitution this is demand management in response to pricing signals.

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

The main risk of bypass is from large customers who may choose to either, connect directly to Transpower's network and thus bypass distribution, or who find an alternative source of power such as diesel generation or even a form of cogeneration. TLC addresses this risk by offering non standard contract pricing and account management to industrial and large customers. Contract pricing is based on the recovery of dedicated assets, infrastructure and maximum required capacity.

(c)(ii) " Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services."

Customers with significant load requirements have individually negotiated contracts that consider price/quality trade-offs such as restriction on loading at certain times or the acceptance of having supply cut during emergencies.

Most other customers are not able to negotiate price/quality trade offs. Due in part to technology constraints TLC is unable to offer the majority of its customer a true price /quality trade-off. Quality of service is a further area of regulatory compliance. TLC is obliged to establish a level of predicted duration of outage and frequency of outage. This is referred to as SAIDI and SAIFI, and breaches of targets incur financial penalties.

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

TLC is actively promoting the purchase and use of technology that allows customers to monitor their kW load. Load Meters are to be installed in the near future. This use of technology, combined with direct billing to customers, enables customers to better understand and manage their load and relative charges.

(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.

TLC is continually working to align itself to this principle. Because TLC invoices its customers directly, it faces great pressure to provide transparency, certainty and stability when setting prices. This principle has a significant role in the development of board strategy, communication policy, and operational processes.

TLC is aware of the financial uncertainties many of its customers face. An annual reset of kW load means that customers have a flat bill for the 12 month period.

The introduction of a Transition Period in the 2012 Pricing Methodology attempts to provide a degree of equity between customers who have chosen to install TOU meters and those still on the legacy standard meters. The situation of inequity that has developed shows the inadequacies of the formulae against the accuracy of the TOU measurement.

(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.

As TLC invoices it customers directly, price development has no impact on retailers. The impact price development has on customers is a major consideration. TLC works hard to keep customers informed as to pricing developments and is frequently involved in public workshops and consultation.

C: Information Disclosure Guidelines Alignment

Commerce Commission

Information Disclosure Guidelines

(a) "Prices should be based on a well –defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.

The Pricing Methodology is disclosed as required in the Electricity Information Disclosure Requirements issued 31 March 2004 and including amendments to 31 October 2008. Material revisions to the 2012 methodology have occurred as a result of expert consultation by Sapere group and resulting public consultation. TLC developed a transition strategy to ensure that metering and data measurement inequities are addressed.

(b)(i) "The pricing methodology disclosed should demonstrate how the methodology links to the pricing principles and any non-compliance."

The Pricing Methodology document has a structure that attempts to provide for all stakeholders a clear message of methodology. The Introduction and Table of Contents provide the outline while the separate sections focus on the methodology identified as the most appropriate means of ensuring allowable recovery of full economic costs.

The Lines Company in 2005 applied for exemption from Low user regulations for identified remote areas. This exemption was granted for the period 2005 – 2015. The exemption certificate and map outline of the remote areas is available on the website and included with the methodology document as an appendix.

(b)(ii) "The pricing methodology disclosed should demonstrate the rationale for consumer groupings and the method for determining the allocation of consumers to the consumer groupings."

The rationale and methodology for customer groups has been presented in the section on Customer Groups.

(b)(iii) "The pricing methodology disclosed should demonstrate quantification of key components of costs and revenues."

The discussion presented in the section on costs identifies the concepts and rationale supporting TLC cost allocation. Full quantification of cost and revenue is presented in the Cost Allocation tables in the Appendices.

(b)(iv) "The pricing methodology disclosed should demonstrate an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping."

The Pricing Principles require that prices are to signal the economic cost of provision; The Lines Company philosophy is to where possible allocate dedicated costs to the connection that benefits. For instance dedicated lines and dedicated transformers. Where a cost item is of benefit to the local network then the cost is distributed between the consumer groups on that network.

It is acknowledged that the Principles require a level of subsidy that prevents a simple cost allocation at a local level. While it costs more to provide capacity to a rural customer the full cost of this service is not allocated. Customer surveys have been returned that support a level of subsidy. The low user tariff is a further anomaly to the principle of full cost allocation. Low user tariff of less than 15 cents per day means that other consumers will subsidize these users as the full cost of supplying capacity is the same.

(b)(v) "The pricing methodology disclosed should demonstrate an explanation of the tariffs to be charged to each consumer group and the rational for the tariff design."

The tariffs are split into fixed, variable and asset charges. The different tariff levels are according to region, capacity, voltage and density.

The 2012 tariff schedule is displayed on the Lines Company website.

(b)(vi) "The pricing methodology disclosed should demonstrate pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as

distributed generation or load management, where alternatives are practicable and where network economics warrant."

The negotiated contracts with large capacity consumers are intended to influence those consumers load management. Smaller consumers are being sent a similar message on load management with the variable kW load charge and the introduction of Time of Use meters.

(c)(i) "The pricing methodology should employ industry standard terminology, where possible"

The choice of terminology has been made with clear knowledge of this clause. As TLC invoices the consumer directly it intends to create a plain English document that will attempt to simplify and summarise this Pricing Methodology.
Acronyms are defined in the body of the text. The glossary supplies industry definitions to provide clarity.

(c)(ii) "The pricing methodology should: where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology.

The introduction of optional Time of use meters has meant that some consumers are charged for KW load based on Time of Use assessment rather than formula assessment. There are individual cases where the new measurement has led to a significant price shock. Prior to 2012, TLC provided individual ICPs a one off reassessment of kW load if required. This nominated kW load is used for monthly billing. At the end of the period (TLC reads the meters once a year) the wash-up will be debited or credited to the ICP account. In 2012 TLC has determined to remove these situations of inequity by introducing a transition period whereby customers on TOU meter can opt to have their kW load assessed by profile. The principle drivers of the methodology have not changed just the method whereby the data is assessed.

Total Forecast Cost for 2011-2012			
Cost Category	Cost Line	$000	
Transmission Costs		5,640	
	Transmission sub-total		$ 5,640
Distribution Costs			
Maintenance	Systems Maintenance	1,967	
	Faults	1,150	
	Asset Management	2,137	
	Generator Liaison	50	
	Maintenance		$ 5,304
Value-related costs	Rates	120	
	Insurance	105	
	Corporate Costs	1,951	
	Depreciation	7,012	
	Rate of Return	13,910	
	Value-related costs		$ 23,098
Customer Costs	Pricing and Customer Liaison	822	
	Data Costs	737	
	Industry Levies	97	
	Customer costs		$ 1,656
Collection Costs		208	
	Collection costs		$ 208
	Distribution sub-total		$ 30,266
	Total Cost Forecast		$ 35,906
	Less Price Path		-$ 1,408
	Total target revenue		$ 34,498

Cost Allocation - Line Length							
	kVA density		33kV	11kV	400V	Total length	Cost
			km's	km's	km's	km's	$000
Hangatiki	high		71	471	171	713	918
	low		22	862		884	709
Ongarue	high		57	254	161	472	692
	low		15	580	80	675	638
National Park				238	24	262	224
Ohakune				123	50	173	191
Tokaanu	high		75	94	100	269	510
	low		0	105	10	115	98
Whakamaru	high		38	36	10	84	168
	low		38	469	28	535	525
Contracted			34	119		153	197
			350	3351	634	4335	$ 4,871
Cost per km			$ 3.20	$ 0.74	$ 2.00		

Cost Allocation - customer costs			
Cost Line			$000
Pricing and Customer Liaison			822
Data Costs			737
Industry Levies			97
			$ 1,657
less			
	Large	-153	
	Contracted	-99	-$ 251.50
			$ 1,405

Cost Allocation by customer numbers				
Network region			ICP	Cost
		density	no.	$000
Hangatiki		high	7165	415
		low	2013	117
Ongarue		high	3687	213
		low	1295	75
National Park		high	798	46
		low	93	5
Ohakune		high	1637	95
		low	294	17
Tokaanu		high	3800	220
		low	1001	58
Whakamaru		high	2132	123
		low	358	21
	totals		24273	$ 1,405.22

Cost Allocation - Maintenance			
Cost lines			$000
Maintenance			5304
LESS			
Generator Liaison		50	
Contracted Remote		263	
Transformers		120	
			433
		total	$ 4,871
network line length			
33kV	23%	$ 1,120	
11kV	51%	$ 2,484	
400V	26%	$ 1,266	$ 4,871

Cost Allocation - Value -related costs	
cost line	$000
Rates	120
Insurance	105
Corporate Costs	1,951
Depreciation	7,012
Rate of Return	13,910
total	$ 23,098

Value - related Costs

	density	Replacement	Regulatory Value	Transformers	Contracted	Total	Value - Related
		$000	$000	$000	$000	$000	$000
Contracted		17,758				13,213	1,927
Transformers		30,035				14,973	1,959
Hangatiki	high	57,627	34,363	- 3,417	- 4,408	26,539	3,957
	low	46,618	26,926	- 3,819		23,107	3,100
Ongarue	high	34,251	20,357	- 1,206	- 100	19,051	2,344
	low	32,193	18,403	- 1,809		16,594	2,119
National Park	low	22,806	13,008	- 603	- 3,152	9,254	1,498
Ohakune	high	20,185	11,569	- 502	- 4,744	6,322	1,332
Tokaanu	high	24,325	13,854	- 402	- 493	12,959	1,595
	low	7,742	4,414	- 100		4,314	508
Whakamaru	high	1,504	859	- 201	- 66	592	99
	low	40,629	23,102	- 2,914	- 249	19,939	2,660
	total	$ 335,672	$ 166,855	-$ 14,973	-$ 13,213	$ 166,855	$ 23,098

Cost Allocation Summary								
	Transmission	Maintenance	Value-related	Customer	Collection	Total	Price Path adjustment	Target revenue
	$000	$000	$000	$000	$000	$000	$000	$000
Hangatiki	2,676	1,711	7,057	588	70	12,102	-330	11,775
Ongarue	1053	1,330	4,463	297	42	7,185	-2,232	4,952
National Park	247	127	851	55	7	1,287	584	1,871
Ohakune	428	191	1,332	95	12	2,058	251	2,309
Tokaanu	662	607	2,103	299	21	3,692	880	4,573
Whakamaru	165	694	2,759	147	22	3,787	-428	3,358
Contracted	562	379	1927	154	17	3,039	-96	3,133
Generator		50				50		50
Transformer charges		120	1,959		12	2,091	8	2,477
Total	$ 5,793	$ 5,209	$ 22,451	$ 1,635	$ 203	$ 35,291	-$ 1,363	$ 34,498

Cost subisdisation by region				
	Cost	Revenue	subsidy	%
Hangatiki	14760	14792	32	0.2%
Ongarue	7624	5441	-2183	-28.6%
National Park	2011	2623	612	30.4%
Ohakune	2751	2853	102	3.7%
Tokaanu	3861	4863	1002	26.0%
Whakamaru	4287	3926	-361	-8.4%
Total	$ 35,294	$ 34,498	-796	-2.3%

Cost subsidisation by Trust region				
	Cost	Revenue	subsidy	%
Waitomo	19,047	18,718	-329	-2%
King Country	16,246	15,780	-466	-3%

Hangatiki

Regional Allocation: Hangatiki										
Allocation		Transmission		Distribution				Total cost	Price Path	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection			
		$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted		112	200	281	102	849	9	1553	253	1806
33kV		19	61	91		76	1	248	60	308
11kV		197	612	209	57	1233	13	2321	-102	2219
400V	high density	326	1014	701	415	2723	30	5209	1443	6652
	low density	109	341	709	117	3100	25	4401	-1808	2593
	totals	$763	$2,228	$1,991	$691	$7,981	$78	$13,732	-$154	$13,578

Regional: Hangatiki: Apportionment of Costs				
		33kV	11kV	400V
Contracted		actual		
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional: Hangatiki: Customers		
Contracted		1
33kV		1
11kV	industrials	19
11 KV	low density	2835
400 V	high density	6238
		9094

Regional:Hangatiki: Replacement Cost			
			$000
Contracted			9,957
33kV			15,854
11kV	urban		41,773
			$ 57,627

Regional: Hangatiki: Statistics		
		kW load
Contracted		6841
33 kV		1193
11 kV	industrials	12,058
11 kV	low density	6712
400 V		19970
		46774

Ongarue

Regional Allocation: Ongarue												
Allocation		Transmission		Distribution				Total cost	Subsidy	Price Path	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection				
		$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted				6	2	13		21		-22	
33kV								0			
11kV		9	24	28	9			70		60	131
400V	high density	218	568	664	213	2,344	23	4030		-496	3535
	low density	65	169	638	75	2,119	18	3084	-1075	-721	1,287
	totals	$292	$761	$1,336	$299	$4,476	$41	$7,205	-$1,075	-$1,179	$4,953

Regional: Ongarue: Apportionment of Costs				
		33kV	11kV	400V
Contracted				
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional: Ongarue: Customers		
Contracted		
33 kV		
11 kV		3
400 V	high density	3398
400 V	low density	1507
		4908

Regional:Ongarue: Replacement Cost			
			$000
Contracted			
33kV			13,587
11kV	urban		33,093
400V			6,724
			$ 53,404

Regional Statistics: Ongarue		
kW load		
Contracted		
33kV		
11kV		416
400V	High density	9,910
	Low density	2,955
	total	13,281

National Park

Regional Allocation: National Park											
Allocation		Transmission		Distribution				Total cost	Price Path	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection			
		$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted		92	77	52	13	396	4	634	57	691
33kV										
11kV					3			3	185	188
400V	high density	18	29	25	46	164	2	284	495	779
	low density	76	123	103	5	687	6	1000	-96	904
	totals	$186	$229	$180	$67	$1,247	$12	$1,921	$641	$2,562

Regional: National Park: Apportionment of Costs				
		33kV	11kV	400V
Contracted		3085		
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional: National Park : Customers		
Contracted		1
33kV		
11kV		2
400V	high density	475
400V	low density	374
		852

Regional:National Park: Replacement Cost			
			$000
Contracted			3,085
33kV			6,347
11kV			8,626
400V			900
			$ 18,958

Regional Statistics: National Park			
kW load			
Contracted			2,483
11kV (contracted share of common)			
11kV (Industrials)			492
400V	High density		2,064
	Low density		1,943
		Total	6,982
	Total of Common		4,499

Ohakune

Regional Allocation: Ohakune										
Allocation		Transmission		Distribution				Total cost	Subsidy	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection			
		$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted		26	44	26	18	506	4	624	-157	467
Transformers										
33kV										
11kV				28		194	1	223	-130	93
400V	high density								2209	2209
	low density	78	350	163	95	1138	11	1835	-1830	5
	totals	$104	$394	$217	$113	$1,838	$16	$2,682	$92	$2,774

Regional: Ohakune: Apportionment of Costs				
		33kV	11kV	400V
Contracted		actual		
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional:Ohakune: Customers		
Contracted		1
33kV		
11kV		1
400V	high density	1900
400V	low density	10
		1912

Regional:Ohakune: Replacement Cost			
			$000
Contracted			4,678
33kV			
11kV			0
400V			0
			$ 4,678

Regional Statistics: Ohakune			
Demand			
Contracted			2,530
11kV Share of Common			1,265
11kV urban			
400V	high density		7,507
400V	low density		16
		total	11,318
	total of common charge		8788

Tokaanu

Regional Allocation: Tokaanu											
Allocation		Transmission		Distribution				Total cost	Price Path	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection			
		$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted				10	14	55		79	105	184
33kV										
11kV		8	42	39	21	122	1	233	-19	214
400V	high density	92	507	471	220	1473	16	2779	1462	4241
	low density	2	12	98	58	508	4	682	-563	119
	totals	$102	$561	$618	$313	$2,158	$21	$3,773	$985	$4,758

Regional: Tokaanu: Apportionment of Costs				
		33kV	11kV	400V
Contracted		actual		
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional: Tokaanu: Customers		
Contracted		2
33kV		
11kV		7
400V	high density	4616
400V	low density	149
		4774

Regional:Tokaanu: Replacement Cost			
			$000
Contracted			427
33kV			11,440
11kV			10,266
400V			4,707
			$ 26,840

Regional Statistics: Tokaanu			
kW load			
Contracted			
33kV			
11kV	Industrials		1,091
400V	High density		13,154
	Low density		311
		total	14,556

Whakamaru

Regional Allocation: Whakamaru										
Allocation		Transmission		Distribution				Total cost	Price Path	Revenue
		Connection	Demand	Maintenance	Customer	Value	Collection			
		$000	$000	$000	$000	$000	$000	$000	$000	$000
Contracted		9		4	5	32		50	-16	34
33kV										
11kV		9		35	3	190	1	238	-75	163
400V	high density	37		168	123	99	2	429	315	744
	low density	120		490	21	2470	18	3119	-668	2451
	totals	$175	$0	$697	$152	$2,791	$21	$3,836	-$444	$3,392

Regional Statistics: Whakamaru			
kW load			
Contracted			570
33kV	(contracted share of common)		500
11kV			485
400V	High density		2,092
400V	Low density		6,779
		total	9,926
	total of common share		9,856

Regional: Whakamaru: Apportionment of Costs				
		33kV	11kV	400V
Contracted		actual		
33kV		actual		
11kV		80%	10%	100%
400V	high	20%	90%	
	low	actual		

Regional: Whakamaru: Customers		
Contracted		2
33kV		
11kV		1
400V	high density	903
400V	low density	1,582
		2,488

Regional:Whakamaru: Replacement Cost			
			$000
Contracted			
33kV			13,638
11kV			22,447
400V			1,700
			$ 37,785