The Lines Company Limited
Line Charges Methodology
(Amended 30 September 2011)

The Lines Company is the oldest network in New Zealand, supplying some of the remotest installations. Its customers are on the whole not wealthy. We are part way through a major renewal programme that will last for a further 15 years. We believe that our customers cannot afford to fund unnecessary line upgrades in addition to this renewal programme. By making customers aware of the true cost of extra capacity we are hoping to minimise the need for it. Therefore effective from 1 March 2007 variable line charges based on kWhs were replaced by variable charges based on kWs.

Philosophy

Structure

The Lines Company Limited (TLC) is in the business of supplying its connected customers with capacity. It is the long and short term (demand) capacity requirements of its connected customers, rather than the amount of electricity conveyed that determines the investment the company has to make in its network.

The total cost of providing an individual customer with an electricity supply is made up of the following elements:

- Investment and maintenance costs of the assets that are either dedicated to, or are significantly influenced by the capacity requirements of, the customer.
- Investment and maintenance costs of the common network.
- The cost of transmission services.
- Customer related costs e.g. data reconciliation, billing, individual queries.

In order to accurately reflect TLC's costs in providing its network, line charges are payable by connected customers, both load and generation, according to the long and short term capacity those customers require and the assets that are dedicated to providing that capacity.

The ability to charge generation customers a capacity charge may disappear, over time, due to the advent of the Electricity Governance (Connection of Distributed Generation) Regulations 2007. These regulations enact a default charging regime whereby individual generation plants are charged the net marginal cost (benefit) of the connection. This is re-calculated annually and, as the default regime does not give any capacity entitlements, the marginal cost may vary greatly between years due to the requirements of other users. Parties may contract out of the default regime, and it is our current intention to provide capacity based contracts, with associated charges, to those generation customers who are interested in long term security.

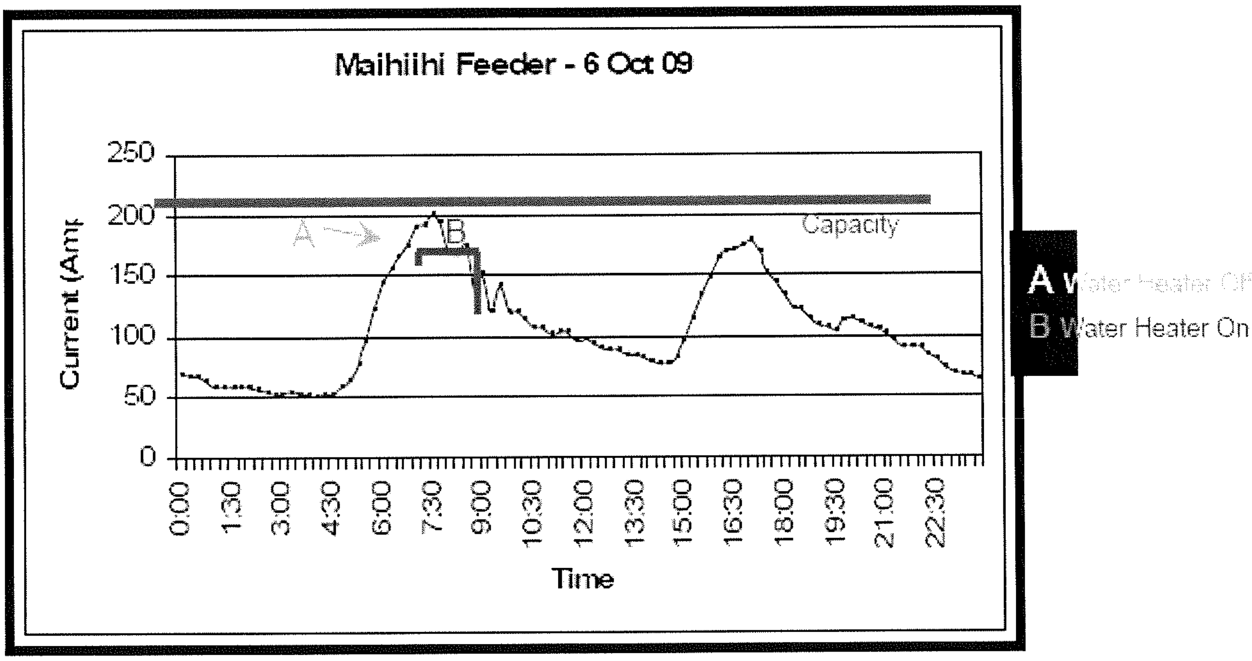
In order to accurately reflect the above cost influences TLC's charging structure is as follows:

1. Individual charges for dedicated assets comprising:
    a. Lines and associated assets – where these are dedicated to the supply of an individual customer and TLC is responsible for their maintenance or renewal.
    b. Transformers and associated assets– where these supply 3 or less customers.
2. A network charge based on contracted capacity.
3. A demand charge based on actual usage over the previous year's peak periods.
4. A customer service charge (for large industrials only).

<u>**Demand Charge**</u>

Why charge on demand at peak times?

If we look at the example below, then we can see that growth at the peak times will eventually cause the existing capacity of the line to be exceeded, requiring us to invest in new assets to supply extra capacity.



If charges are based on this peak time demand requirement then customers have an appropriate incentive to limit their peak time usage. If however charges are based on average demand, peak and off peak, then the incentive to limit peak time usage is weak. In such a scenario, the requirement for new capacity at peak times grows faster than the revenue received; meaning that funding for the new investment has to come from all customers through price increases, rather than just the customers who are benefiting.

This was the scenario that the company found itself in prior to the introduction of demand based charges.

Demand Level

Where a half hour "demand" meter is fitted at a customer's installation then the demand level is calculated by:

(a) For installations above 100 kVA – by taking the highest consumption over any 3 hour period and dividing that by 3. 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 highest consumption over any 3 hour period when we are load controlling the water heating load of the local customers, and dividing that by 3.

It is presumed, as can be seen in the above example, that we will load control at peak times.

Where a half hour meter is not fitted then the demand level is calculated.

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 maximum demand over a 3 hour period when load controlling hot water cylinders.

The sample of installations was chosen at random. It does not include installations where customers have asked for demand meters to be fitted, as it is presumed that such customers would be actively working to control their demand level and therefore the association of uncontrolled energy and demand for such customers would not be typical of the general population.

Weighting

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%.

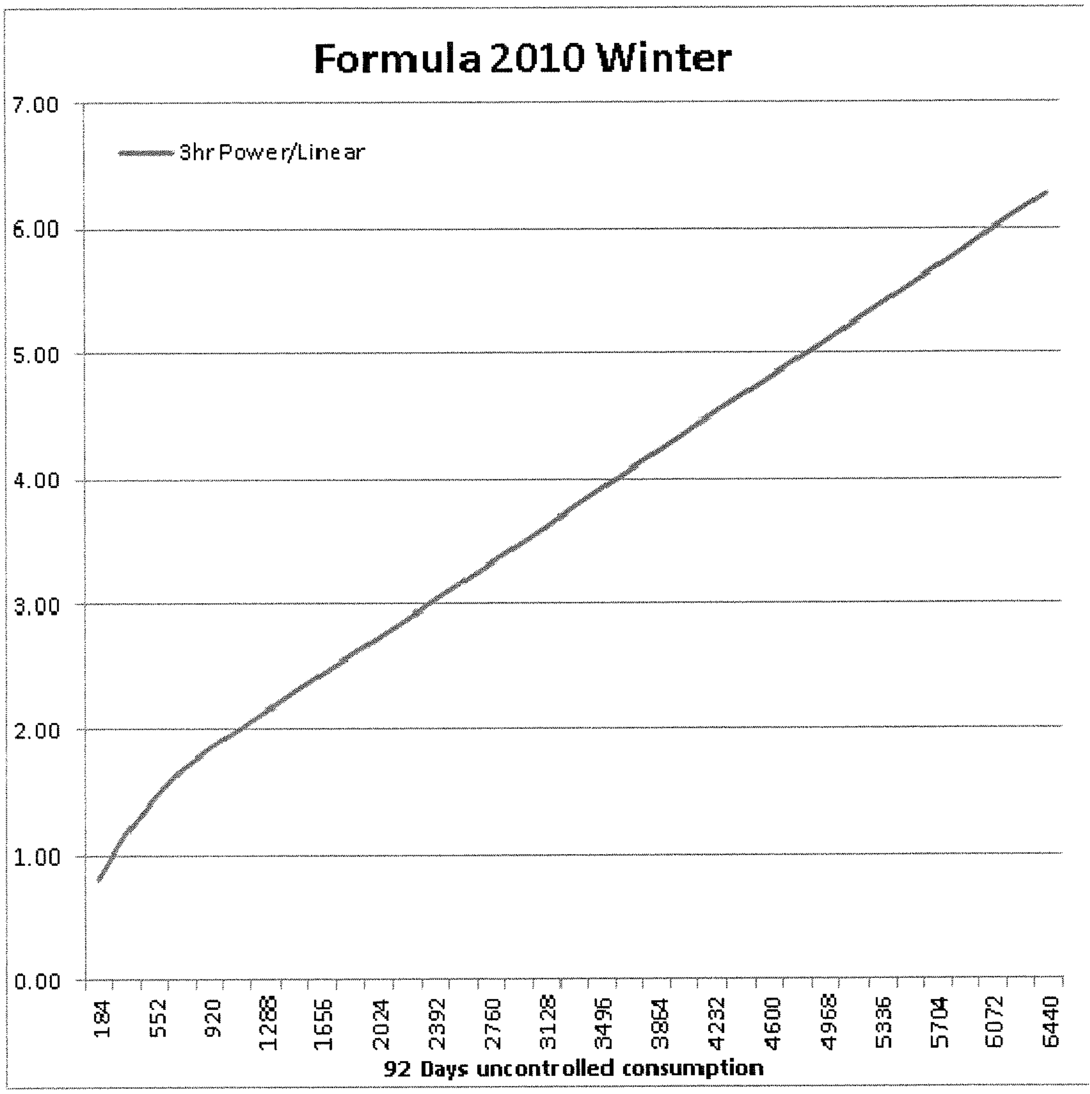
Installations other than Dairy sheds

Actual meter readings between 1 June and 30 September 2010 are used. Where there was only one meter reading available during that period the readings from May and October are 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 demand will remain unchanged.

The daily uncontrolled consumption is calculated between the actual readings, is calculated and then either extended or contracted to 92 days as required.

The total "uncontrolled consumption" as calculated with the above percentages was used in the formulae.

The domestic sample produces the following graph:



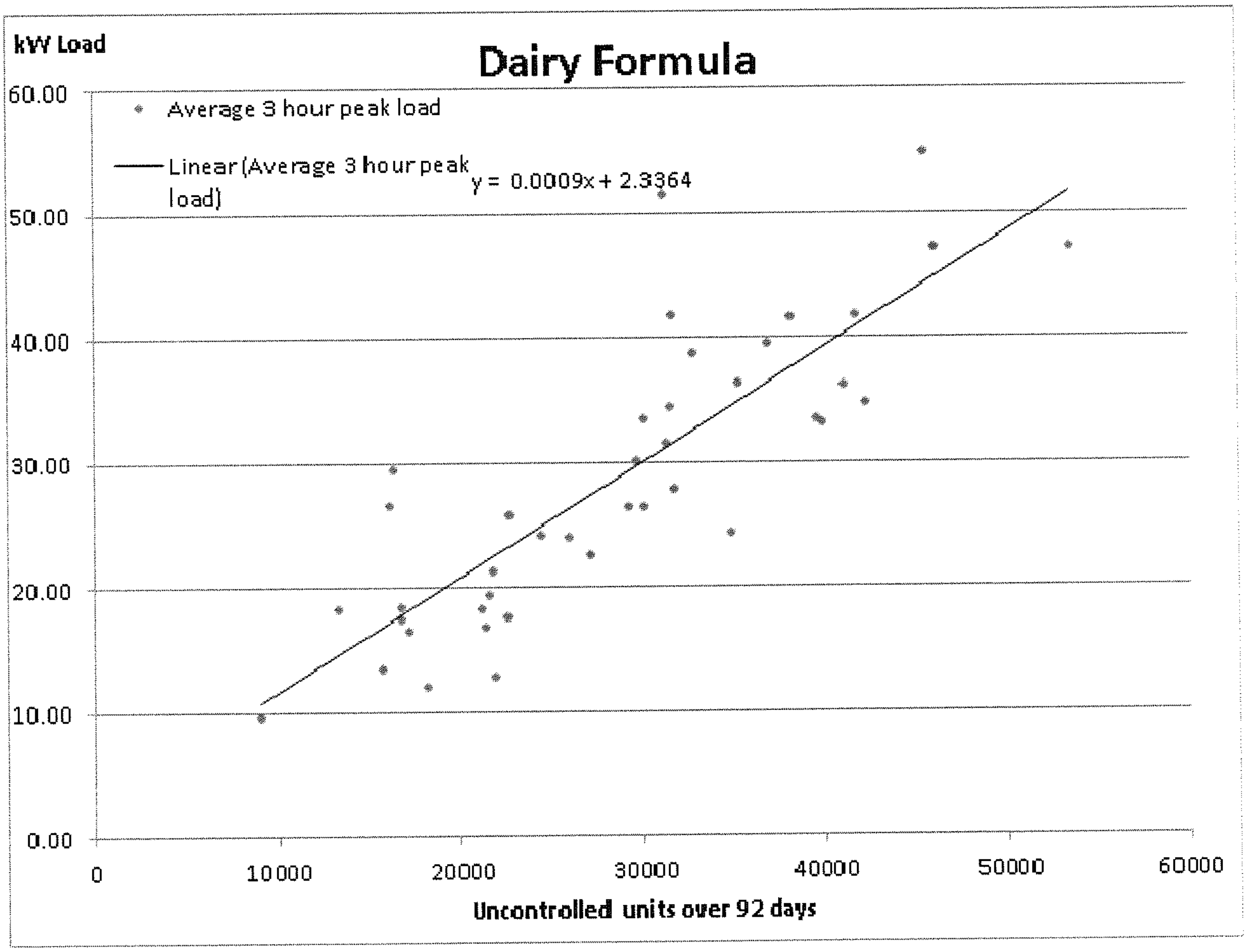
The resulting formulae are shown in *Appendix One*.

Dairy sheds

Lines in dairy farm areas do not peak over winter, and instead peak over August to December with the combination of domestic load and dairy shed load.

The demand is therefore calculated based on meter readings between 1 September and 30 December 2010.

The daily consumption was calculated between the actual readings and extended or contracted to 92 days. A sample of actual demands vs. uncontrolled consumption for dairy sheds over this period produced the following:



The formula used is in *Appendix One.*

Formula Type

Investigation in 2007 centred on the accuracy of the linear equation we were then using for low domestic users. As a result of that investigation a quadratic equation was chosen to ensure that the equation was a reasonably accurate assessment across all four quarters of consumption. The average calculated demand as a percentage of the actual peak demand was 99.9% for the lowest usage quartile and 102.1% for the highest quartile.

The formula is calculated with a combination of linear, quadratic and power equations used in any particular year in order to give the best correlation between uncontrolled consumption and demand for that year, for the particular consumers to which the formula applies.

Exception

The formulae assumes that the installation being measured is either in regular use (i.e. a domestic residence is permanently occupied over the assessment period) or, if it is not in regular use, then the likelihood of it consuming over peak times is in proportion to its use.

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. Holiday homes, therefore do not meet the above assumption.

Standard holiday homes have been given a demand of 2.1 kW. This is amended where there is evidence that a consumer is taking a different demand, e.g.:

- Where the demand formula produces a higher result – as this calculated demand is likely to still be less than the actual demand the calculated demand figure is used.
- Higher fuse sizes, the presence of uncontrolled water heating or submaining, lead to a higher demand level.

We are installing demand meters in a sample of holiday homes to see if there is a significant variation in the demand of holiday homes compared to the demand of permanently occupied residences.

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 half hour demand meter fitted.

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 are experiencing 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 2.0kW 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 fixed charge consumers since 29 March 2010.

Formula accuracy

Comparison of demands calculated by the formulae to the demands of similar sized non-domestic installations measured by half hour meters have confirmed that the formula calculated demands appear accurate. The accuracy of the ski lodge/seasonal business was confirmed by comparing the total peak on a separately metered feed to such businesses with the sum of the assessments on that feed.

We have also received advice from engineers engaged by customers that their individual analysis is that the calculations are accurate, and if not slightly conservative.

Where a customer group has a demand pattern that falls outside the norm of the general population it may pay for half hour meters to be fitted to accurately measure demand.

Demand Period

Once calculated, demands generally come into effect as from 1 April of the subsequent year and remain in effect until 1 April of the following year. Demands may however be recalculated if an error has been made in the original calculation, or more accurate data becomes available.

Demand reassessments

If a demand is recalculated, either by us or at the request of the customer, then if there is not a significant movement in the demand level, the change in demand shall take place with effect from 1 April following. Where the demand change is significant, the assessment shall apply as from 1 month after assessment.

If either TLC or the customer is unhappy with the calculation they can request a demand meter to be installed, following which the customer will be charged on the actual demand measured. This may be backdated to 1 April prior, provided the meter is fitted prior to 1 June following and the customer elects to the backdating prior to the meter being fitted.

Low fixed charge option

See discussion on network charges.

Costs covered

The Demand charge covers the local regional Transmission Costs, the residual local regional network costs not covered by the network charge and the dedicated asset charges, and an element of subsidy towards remote rural lines.

Network Charge

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

In constrained areas the network charge is calculated to produce around 1/3 the revenue required from the combined network and demand charges. For non-constrained areas, the charge is to produce around ½ the revenue required.

Capacity level

Capacity requirements are based on either the capacity, which we have been contracted to supply (normally being the level stipulated on the Connection Application) or, where there is no documentation, it is calculated from the individual's usage over system peak periods. Contracted capacity cannot be lower than the demand (whether measured or calculated) for the installation. Our experience is that for most installations below 100 kVA, capacity is 2x the demand level.

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 where the customer is paying a separate transformer charge.
- A suburban 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 rural 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 meter charges, 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 demand 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.

Rural Costs

TLC covers a wide rural area. It is recognised that supply to rural areas costs more than supply to urban areas. Equally it is recognised that full cost allocation is not current government policy due to its onerous effects.

Most of the 33kV infrastructure is needed to supply the industrial load, which is predominantly urban, and to enable generation to be exported. This infrastructure is needed irrespective of the presence, or absence, of the rural load. It would therefore appear reasonable that the cost of this infrastructure, apart from the Mahoenui line, which supplies only a rural area, should be fully allocated to the urban area, with the rural areas bearing only the marginal cost of the 11kV and 400V network.

Extra income is received from rural areas by increasing the network charge.

It is noted that full cost allocation is not government policy, and instead policy is that the current percentage differential between urban and rural prices should be maintained. Also customers have advised, through surveys, that they are willing to support the current levels of urban/rural cross subsidy, but they do not wish to see them increased.

With the introduction of the transformer charge for dedicated transformers (which are more common in rural areas) and the higher rural network charge, our studies show us that customers on remote rural lines are now paying 2x the amount per kW of demand than those in urban areas. This however is still less than half the cost of supply.

Cost of Capital

We, however, are exposed to a greater risk of asset stranding compared to normal lines companies due to a significant proportion of the asset value being assets dedicated to the supply of a small number of major customers, or to remote rural customers.

Following the determination of input methodologies by the Commerce Commission the rate determined by the Commission will be used. Until then we have had a rate advised by consultants as being close to the rate likely to be set by the Commission based on the work released by the Commission before 31 December 2009.

Revenue

The line charges have been set at a level to recover the following costs:

(a) The purchase of capacity from Transpower and embedded generators.
(b) Network maintenance.
(c) Faults.
(c) Asset management.
(d) Pricing and Customer Liaison.
(e) Data.
(e) Industry levies.
(f) Rates.
(g) Insurance.
(h) Corporate costs.
(i) Depreciation.
(j) Cost of capital.
(k) Collection cost.

Past price thresholds have not enabled us to recover full recovery costs. As a result our renewals programme has been compromised. Prices have been increased, to enable a greater level of renewal expenditure. Prices will not however still fully recover costs. It is intended to agree with the trust owners about who should be paying the cost of the supply to remote rural areas and close the gap between revenue and costs, in line with that decision, over time.

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 into those taking supply:

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

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.

Regional Allocation

Costs are allocated to each region on the following basis:

(a) Transpower costs according to actual costs.
(b) Network maintenance, asset management, faults, insurance, and rates, according to line length and specific voltage costs. The cost is first assigned to voltages by historic split.
(c) Liaison costs, industry levies, data, and corporate costs according to customer numbers, with a minimum for large industrial customers of $1000.
(d) Depreciation according to Regulatory Book Value (RBV). To derive the adjusted RBV the actual RBV for the region before economic write down is adjusted so that it has the same ratio to replacement cost as the total network RBV has to the total network replacement cost. This adjustment is undertaken so that a high asset renewal programme in any area does not necessarily lead to a significant change in charges.
(e) Cost of capital is according to asset value.
(f) Subsidisation cap – no region is expected to earn revenue more than its costs plus 5% (in accordance with our customer surveys); the benefit of the cap falls mainly to those areas that have traditionally been subsidised.
(g) Regulatory cap – under recovery due to price thresholds uncertainty.

Dedicated Transformers

Consistent with our methodology, a charge to recover the cost of dedicated transformers has been introduced. Each transformer size has been assigned a value based on replacement costs, including the transformer itself, site establishment costs including earthing, and associated fuses. The cost is depreciated by 40% to reflect the average age of our transformer assets. The charge is set at a level to recover maintenance costs, depreciation, an after tax return, and collection costs. Customers who own their transformers, associated connection assets and earthing avoid this charge.

Dedicated Lines

Dedicated lines are currently provided to BHP NZ Steel Mining, McDonald's Lime, Ruapehu Alpine Lifts, Winstones, Council street lights and the Department of Corrections. The line charges for these customers are set by individual contract and are designed to provide a return on our investment over the economic life of the assets.

The maintenance cost of other dedicated lines generally resides with the customer. The charge for other dedicated lines applies only where it is agreed that we have the maintenance responsibility. This enables customers to accurately assess the cost of maintaining their own lines.

The charge is calculated on a per km basis by adding together:

1. The maintenance cost for the relevant line voltage.
2. Depreciation on replacement cost.
3. Capital cost at the rate for dedicated assets open to stranding, multiplied by half the replacement cost.
4. The standard collection cost margin.

Transmission Charges

Are calculated as follows:

(a) Connection charge divided by the total summed demands for the region.
(b) Contracted customers: Total of the 100 Transpower co-incidental peaks adjusted for losses multiplied by the Transpower kW demand rate.
(c) Remaining: The demand cost for the region minus the above divided by the total summed demands for the region less the above.

Other Costs

Costs are assigned to groups based on the ratio of the group demand to the total demand taking supply at that level; provided that to recognise the marginal cost of rural customers, and the fact that most industrial customers are in the urban area, the 11kV cost allocated to 11kV customers is lowered by 28%, and the 33kV cost allocated to 11kV customers is increased by 26%.

Collection Charges

All charges have been increased to reflect the cost of collection. This cost is based on the responses to a request for proposals issued in 2004, adjusted by CPI since.

Dedicated Line Charge

A charge has been introduced for lines that are dedicated to the supply of single customers, but whose maintenance is the responsibility of the customer. Most customers currently accept the maintenance costs of these dedicated lines. It is only intended to introduce the charge where both the customer and TLC accept that TLC is responsible for current maintenance or should be responsible for the future maintenance.

Prompt Payment Discount and GST

All revenues shown are after the application of a prompt payment discount, currently 10%. To calculate total prices, the rates derived by following the methodology are divided by 0.9. The rates derived do not include GST, which is added on the account.

Issues Going Forward

Prior to next year's price movement we are expecting robust discussions with the trusts on the size of subsidisation:

a. to remote rural customers.
b. between regions within trust areas.

Appendix One

Formulae

2011/2012

2011 Formulae

The formula is calculated with a combination of linear, quadratic and power equations used in any particular year in order to give the best correlation between uncontrolled consumption and demand for that year, for the particular consumers to which the formula applies.

1. The following formula applies for those customers who use less than 777 kWhrs of uncontrolled consumption over a 92 day period (June - September).

   (0.1567*consumption^0.5259)/3

2. The following formula applies for those customers who use more than 777 kWhrs of uncontrolled consumption over a 92 day period (June – September).

   ((0.0024*consumption)+3.3359)/3

3. The following formula applies for those dairy sheds whose uncontrolled consumption is metered over a 92 day period between 1 September – 31 December.

   (0.0009*consumption)+2.3364

If no meter readings within the periods described are available then meter readings outside of these months may be used.

Where;
* = times
^ = to the power of
/ = divided by

Appendix Two

2011/2012 Application

COSTS	
	$ 000's
Transmission	5570
system maintenance	1761
faults	1045
Asset Management	1633
Pricing & Customer liasion	655
generator liason	50
Data costs	310
Industry levies	134
Insurance	90
Rates	105
Corporate costs	1684
Depreciation	6913
Collection costs	447
Cost of capital	13973
	34370
price path	-2370
	32000

Transmission Costs

Actual charges from Transpower and Payments to Generators for each region.

Collection Cost

% of total costs

Network Maintenance Allocation		
Engineering & Maintenance Total		4489
less generator liasion		-50
less contracted remote		-263
less transformers		-120
		4056
33 kV	23%	933
11kV	51%	2069
LV	26%	1055
		4056

allocation on line length					
	33kV	11kV	400V	total length	cost
Waitomo - high	71	471	171	713	764
- low	22	862		884	591
Taumarunui - high	57	254	161	472	577
- low	15	580	80	675	531
National Park		238	24	262	187
Ohakune		123	50	173	159
Turangi - high	75	94	100	269	424
- low	0	105	10	115	81
Whakamaru - high	38	36	10	84	140
- low	38	469	28	535	437
Contracted	34	119		153	164
	350	3351	634	4335	4056
cost per km	2.67	0.62	1.66		

Customer costs	
Pricing and customer liaison	655
Data	310
Industry levies	134
	1099
less large	-153
less contracted costs	-99
	848

Allocation by Customers		
	Customers	**Cost**
Waitomo	6330	220
	2900	101
Taumarunui	3527	123
	1640	57
National Park	509	18
	383	13
Ohakune	1904	66
	15	1
Turangi	4622	161
	80	3
Whakamaru	948	33
	1534	53
	24392	848

Value related	
Rates	105
Insurance	90
Corporate costs	1683.7
Depreciation	6912.8
Return	13973
	22764

Asset Value		replacement	reg value	transformers	contractors	total	value based
contracted		$ 17,758		$ -		9474	1593
transformers		$ 30,035				14973	2189
Waitomo	high	$ 57,627	34363	-$ 3,417	-$ 4,614	26333	3909
	low	$ 46,618	26926	-$ 3,819		23107	3063
Taumarunui	high	$ 34,251	20357	-$ 1,206	-$ 100	19051	2316
	low	$ 32,193	18403	-$ 1,809		16594	2094
National Park	low	$ 22,806	13008	-$ 603	-$ 3,014	9392	1480
Ohakune	urban	$ 20,185	11569	-$ 502	-$ 1,203	9863	1316
Turangi	urban	$ 24,325	13854	-$ 402	-$ 428	13024	1576
	rural	$ 7,742	4414	-$ 100		4314	502
Whakamaru	urban	$ 1,504	859	-$ 201	-$ 66	592	98
	rural	$ 40,629	23102	-$ 2,914	-$ 49	20139	2628
		$ 335,672	$ 166,855	-$ 14,973	-$ 9,474	$ 166,855	$ 22,764

Capital Cost

			2011	2012
regulated		7.69%		
less projected base cpi movement		1.78%		
net		5.91%	post tax	
pre tax		8.21%		
			2011	**2012**
opening			139197	162730
commissioned			8200	7153
cpi			1.83%	1.78%
revaluation			2545	2788
depreciation			-5900	-6229
			144041	166442
non system			684	700
regulatory value			139197	162730
non system			684	700
finance	2.5%		3410	
commissioned during year			8200	7000
Cap interest	8.77%			153
average			4100	3500
total			147391	167084
return			11791	12848
less cpi			-2545	-2788
net			9247	10060
post tax	0.72		13209	13973

Summary

	transmission	maintenance	customer	value related	collection	total	revenue	diff
contracted	568	360	153	1593	34	2707	2993	286
generator		50				50	50	0
transformer charges		120	0	2189	31	2340	2450	111
Waitomo	2330	1424	378	6973	148	11252	10840	-411
Taumarunui	877	1108	189	4410	87	6670	4690	-1980
National Park	188	102	34	1480	24	1828	1662	-166
Ohakune	347	158	66	1316	25	1912	2028	115
Turangi	765	506	184	2078	47	3580	4041	461
Whakamaru	165	578	89	2726	47	3605	3245	-360
total	5241	4405	1094	22764	442	33944	32000	-1944

by region	Cost	Revenue	Difference	
Hangatiki	14008	13500	-508	-3.6%
Ongarue	7190	5209	-1981	-27.5%
National Park	2571	2426	-145	-5.6%
Ohakune	2280	2461	181	8.0%
Tokaanu	3735	4306	572	15.3%
Whakamaru	4122	3763	-359	-8.7%
	33905	31666	-2240	-6.6%

by trust region			
Waitomo	18130	17263	-5%
King Country	15776	14403	-9%

Waitomo/Otorohanga

Allocation	transmission		maintenance	customer	value	collection	total cost	price path	revenue
	connection	demand							
Contracted	108	200	278	102	847	20	1556	-24	1531
33 kv	21	59	77		82.04	3	242	56	298
11 kv	182	514	172	57	1212	28	2166	-104	2063
400 kV high density	303	858	584	220	2697	61	4724	1268	5993
400 kV low	103	290	591	101	3063	55	4203	-1817	2386
Relays									101
	717	1922	1702	480	7902	168	12891	-620	12372

Statistics	
Demand kV	kV
Contracted	6992
33 kV	1337
11 kV industrials	11735
high density	19581
low density	6623
	46268

Apportionment of costs	33kV costs	11kV costs	LV costs
Contracted	actual		
33 kV	actual		
11 kV	80%	10%	100%
high	20%	90%	
low	actual		

Replacement cost ($'000)	
contracted	9,957
33 kV	15,854
11 kV	41,773
400 V	
	57,627

Transmission	
connection	717019
kW	46268
cost per kW	15.50
Charge per kW	17.66
monthly	*1.47*
interconnection	1921771
contracted	-199987
net	1721784
kW	39275.99
cost per kW	43.84
Charge per kW	49.96
Connection + Interconnection	67.62
Monthly	*5.63*

Turangi

Allocation	transmission connection	transmission demand	maintenance	customer	value	collection	total cost	subsidy	revenue
Contracted	0		8	14.5	53	1	77	110	187
33 kv							0	0	
11 kv	28	47	43	21	160	4	304	-83	221
400 kV high	252	420	381	161	1416	35	2665	963	3628
400 kV low	6	10	81	3	502	8	611	-479	132
Relays									60
	287	478	514	199	2131	48	3657	512	4228

Statistics	
Demand kV	kV
Contracted	0
33 kV	0
11 kV industrials	1241
high density	10988
low density	266
	12496

Customers	
contracted	2
33 kV	
11 kV	7
high density	4622
low density	80
	4711

Apportionment of costs	33kV costs	11kV cost	LV costs
Contracted	actual		
33 kV	actual		
11 kV	80%	10%	100%
high	20%	90%	
low	actual		

Transmission	
connection	286868
kW	12496
cost per kW	22.96
Charge per kW	26.16
monthly	*2.18*
interconnection	478007
contracted	
net	478007
kW	12496
cost per kW	38.25
Charge per kW	43.59
Connection + Interconnection	69.76
Monthly	*5.81*

Replacement cost ($'000)	
contracted	362
33 kV	11,440
11 kV	10,266
400 V	4,707
	26,775

National Park

Allocation	transmission connection	transmission demand	maintenance	customer	value	collection	total cost	price path	revenue
Contracted	99	77	43	13	409	8	649	21	670
33 kv							0		
11 kv	0	0	0	3	213	3	218	-30	188
400 V - high	20	29	27	18	595	9	699	-81	617
400 V - low	57	82	75	13	672	12	911	-63	848
Relays									9
	177	188	145	46	1889	32	2477	-154	2332

Statistics	
Demand kV	kV
Contracted	2935
Share of common	
11 kv	604
400V High	1691
400V low	1909
Total	7139

Customers	
contracted	1
33 kV	
11 kV	2
high density	509
low density	383
	895

Transmission	
connection	241033
kW	7139
cost per kW	33.76
Charge per kW	38.48
monthly	*3.21*
interconnection	280195
contracted	-77125
net	203070
kW	4204
cost per kW	48.31
Charge per kW	55.05
Connection + Interconnection	93.53
Monthly	*7.79*

Replacement cost ($'000)	
contracted	2,947
33 kV	6,347
11 kV	8,626
400 V	900
	18,820

Whakamaru

Allocation	transmission connection	transmission demand	maintenance	customer	value	collection	total cost	price path	revenue
Contracted	9		3	5	16	0	33	1	34
33 kv							0		
11 kv	8		27	3	175	3	217	-17	194
400 kV high	33		140	33	98	4	308	312	686
400 kV low	124		410	53	2453	40	3081	-600	2338
Relays									28
	174	0	581	94	2742	47	3638	-304	3279

Statistics

Demand kV	kV
Contracted	570
33 kV Share of common	500
11 kV industrials	479
high density	1915
low density	7188
Total	10152

Customers	
contracted	2
33 kV	
11 kV industrials	1
high density	948
low density	1534
	2485

Apportionment of costs	33kV costs	11kVcosts	LV costs
Contracted	actual		
33 kV	actual		
11 kV	80%	10%	100%
high	20%	90%	
low	actual		

Replacement cost ($'000)	
contracted	
33 kV	13,638
11 kV	22,447
400 V	1,700
	37,785

Transmission	
connection	175049
kW	10152

Taumarunui

Allocation	transmission		maintenance	customer	value	collection	total cost	price path	revenue
	connection	demand							
Contracted			5	2	14	0	22	0	22
33 kv									
11 kv	9	20	25	9	381	6	450	-323	127
400 V -high	193	453	552	123	1935	43	3298	-49	3249
400 V-low	61	142	531	57	2094	38	2922	-996	1256
Relays									58
	262	615	1113	191	4424	87	6692	-1367	4712

Statistics

Demand kV	kV
Contracted	0
33 kV	0
11 kV industrials	436
high density	9662
low density	3029
	13127

Customer	
contracted	
33 kV	
11 kV	3
high density	3527
low density	1640
	5170

Apportionment of costs

	33kV costs	11kV co:	LV costs
Contracted	0		
33 kV	actual		
11 kV	80%	10%	100%
high	20%	90%	
low	actual		

Replacement cost ($'000)

contracted

Transmission	
connection	262311
kW	13127
cost per kW	19.98
Charge per kW	22.77
monthly	*1.90*
interconnection	615059
contracted	0
net	615059
kW	13127
cost per kW	46.86
Charge per kW	53.40
Connection + Interconn	76.17
Monthly	*6.35*