



ELECTRICITY LINE CHARGES

COST ALLOCATION & PRICING
METHODOLOGY

Effective 1 November 2001

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1. INTRODUCTION

This document explains the pricing methodology applied by Powerco to charge Network Users for utilisation of the electricity network assets. This methodology has been derived from the higher level pricing principles as agreed by Powerco's Board of Directors.

These pricing principles are;

1. Powerco will be proactive in meeting regulatory and industry requirements through pricing initiatives.
2. Powerco's line charges will be inclusive of distribution and transmission costs.
3. Powerco will recover distribution costs across Network User groups and geographical regions as cost reflective as practicable.
4. Powerco pricing will be kept as simple and as administratively efficient as practicable.
5. Powerco's pricing methodology will not disadvantage any Network User.
6. Powerco's pricing data will be independent of individual consumer kWh meter readings.
7. Powerco will invoice on calendar month end.
8. Powerco will wash-up its billing monthly.
9. Powerco's pricing methodology will provide signals to encourage demand-side participation in demand management.
10. Powerco's pricing will endeavour to ensure that customer line costs will be relatively stable over time.

This document contains all information required to be disclosed under section 24 of the Electricity (Information Disclosure) Regulations 1999 and Electricity (Information Disclosure) Amendment Regulations 2000.

2. NETWORK USER GROUPS

In order to be fair to all Network Users the line pricing needs to reflect as far as practicable the use that Network Users make of the network assets in the transport of energy to them.

In determining the grouping of connections a trade-off is required between simplicity necessary to reduce processing costs and the level of complexity required to fairly allocate costs while providing appropriate pricing signals to the relevant Network Users.

Powerco uses three Connection Groups for cost allocation and charging purposes,

1. less than 100kVA Connections (E1),
2. 100-299kVA Connections (E100) and
3. 300kVA and above Connections (E300).

All connections default to the E1 Connection Group and must apply and meet certain criteria to move into the other groups (See Sections 5.1.1 & 5.2.1).

3. GROUPING OF GXPS

Each Group was then collated together according to those supplied by distribution network assets connected to each Transpower Grid Exit Point (GXP). For the purposes of allocation of costs to the Connection Groups, GXPs are grouped together where there is a high level of interconnection of network assets i.e. aggregated GXP costs apply when connection load can be switched between one GXP and another. Further aggregation of GXPs cost has been introduced so that pricing is similar between areas with similar connection loading and densities.

3.1 COST ALLOCATION

Since the split of line and energy pricing in 1993 Powerco has closely followed the SOLEC Methodology contained in the Electricity Disclosure Guidelines issued by the then Ministry of Commerce. Use of this allocation methodology is continued in order to divide the distribution costs between the E1, E100 and E300 Connection Groups (described above). Transmission costs are allocated according to each group's contribution to the peak demand at the individual GXP. This reflects the use of the different types of network assets by each Group.

3.1.1 Allocation of Distribution Costs

The allocation of Network Costs to each Connection Group is as follows:

1. Costs consisting of return on network assets, operations & maintenance, depreciation, return on other assets and corporate costs ("Network Costs") are allocated to Network GXPs by cost drivers as shown in Figure 1 and Figure 3.
2. The Network Costs at each GXP (or group of GXPs) are split between E1, E100 and E300 Connection Groups by a proportion derived using the SOLEC guidelines and are shown in Figure 3.
3. Some Connections are fixed in the pricing process for the reason that they are located near a GXP and the average standard group charges are unreasonably high.

3.1.2 Allocation of Transmission Costs

Transmission costs are allocated to each Connection Group as follows:-

1. Transmission capacity costs are allocated to individual GXPs on the basis of actual costs.
2. The costs at each GXP (or aggregation of GXPs) are split between E1, E100 and E300 Connection groups by their proportion of maximum demand as shown in Figure 3.

The cost allocation process is shown diagrammatically in Figure 1.

4. SOURCE OF QUANTITIES FOR LINE CHARGES

The method and structure of Line Charges determines what quantities are required for billing purposes.

Powerco customers are predominantly Electricity Retail Companies and given the Connection Groups described above, Powerco plans to continue to use GXP data to derive the quantities necessary for monthly billing of its Line Charges. This data is deemed accurate, acceptable to all parties and readily available through the National Reconciliation Manager (NRM). In using data supplied by the NRM Powerco is also committed to apply the NRM washup files when generated as part of the NRM washup cycle. Should the data be unavailable from the NRM then Powerco will produce an estimated invoice based on the previous months invoice and this will be adjusted when NRM data becomes available.

In certain cases data may not be available through the NRM e.g. totally embedded generation that is not reconciled. In such cases connection metered data will be obtained through appropriate agreements and converted to GXP based data by applying the appropriate distribution network loss factor(s).

To establish the quantities for the E1 connection group, the E300 and E100 group loads are subtracted from the gross load at the GXP (gross load = busload + embedded generation data). A GXP peak waiver process will be implemented as part of the calculation of the E1 groups peak demand given that load shifting between interconnected GXP's has occurred and created an artificial peak or abnormal demand.

For E300 and E100 connection groups site metered data will be obtained through appropriate agreements and adjusted to GXP based data by adding the appropriate distribution network losses. This TOU metering data should mirror the data being submitted into the NRM process.

For TOU metered connections new to the E300 and E100 groups any historic TOU metering data up to 12 months previous must be provided prior to the start date.

The Retailer must provide TOU metering data in the format specified to Powerco or our nominated agent within 4 business days from the end of the prior month for any Connection within the E300 and E100 Connection Groups. Should Connection TOU metering data not be provided within the timeframe or if it is proven by Powerco to be inaccurate, then the Connection will be removed from the invoicing run and the data will be invalidated for network invoicing in that group until such time as accurate data is provided. Should the data not be remedied by business day 8 then the charges will be determined by an estimate based on the previous month's invoice.

Note: Inaccurate Connection TOU metering data, if not corrected prior to the E1 group data file run on business day 8, will impact on and may be included in the Line Charges invoiced to the E1 Connection Group. Should individual Connection TOU metering data provided be used to create Line Charges and is then found to be inaccurate, Powerco reserves the right to decide if any adjustment of Line Charges based on the individual Connection TOU metering data will be actioned.

5. DESCRIPTION OF LINE CHARGE COMPONENTS, QUANTITIES AND PRICE SIGNALS

Powerco's Line Charging regime provides appropriate signals to Network Users so that they can control their costs by modifying their use of the assets. The basis of the Line Charges also reflect the level of asset used by the Connection and Connection Group in order to be fair and reasonable.

5.1 E300 CONNECTION GROUP

5.1.1 E300 Connection Group General Requirements

To qualify for charging under the E300 group, the Connection must have a dedicated installed distribution transformer (11kV/400v) capacity (nameplate rating) of 300kVA or greater and MARIA compliant Time of Use (TOU) metering. E300 Connections can only change Retailers on the first day of the month. A minimum contract period of 12 months (once accepted to this group) applies.

5.1.2 E300 E3A Network Asset Charge

The E300 E3A Charge is designed to improve installed asset utilisation and to be reflective of the Network Costs associated with the dedicated network assets installed to supply the Connection.

Definition of Chargeable Quantity

The E300 E3A chargeable quantity ("Installed Transformer Capacity") shall be the sum of all nameplate kVA ratings of distribution transformers connected to supply the Connection, irrespective of ownership of the distribution transformers .

Where the deliverable capacity is restricted to a lower level by an item of Powerco's plant then the E3A Installed Transformer Capacity shall be the maximum deliverable capacity in kVA, and shall not be less than 300kVA

E300 E3A monthly charge = \$1.50 x Installed Transformer Capacity (kVA)

5.1.3 E300 E3L Demand Charge

The E300 E3L charge is designed to improve system utilisation by providing a peak demand cost signal and to be reflective of the Network Costs associated with the shared network assets installed to supply the Connection. This allows consumers to control their costs by reducing their overall peak and signals the cost of additional network investment.

Definition of Chargeable Quantity

The E300 E3L Chargeable kVA Demand will be determined using the individual Connection's kVAh ½ hour volume data and is calculated by averaging the top 12 daily anytime maximum kVA demands (one peak per day) on a rolling 12 months basis. The E3L Chargeable kVA Demand will be either a minimum 300kVA or the actual average

demand, whichever is the higher. Where an E300 Connection changes Retailer the load history used to calculate the E3L Chargeable kVA Demand will be transferred with that Connection to the new Retailer.

For new E300 Connections the establishment of the Chargeable kVA Demand for the E3L charge will begin from the installation of the TOU metering, that is, if six months TOU history is available then the 12 peaks will be calculated using the six months data or if only one months TOU data is available the first month's invoice will have the 12 daily anytime maximum kVA demands occurring in the previous month.

E300 E3L monthly charge = E3L Charge (\$/kVA) x Chargeable kVA Demand

5.2 E100 CONNECTION GROUP

5.2.1 E100 Connection Group General Requirements

To qualify for charging under the E100 group, the Connection must have installed MARIA compliant TOU metering. A minimum contract period of 12 months once accepted to this group applies. E100 Connections can only change Retailers on the first day of the month.

5.2.2 E100 E1A Network Asset Charge

The E100 E1A charge reflects a portion of the fixed charges required to operate the network and is intended to be generally reflective of the Network Costs associated with the dedicated network assets installed to supply the Connection. The basis for the level of charge is a 100kVA installed transformer of \$2.50/kVA/month.

E100 E1A monthly charge = \$250.00

The number of E1A charges per E100 Connection will be per installation control point (ICP) connected (normally 1 E1A charge per ICP).

5.2.3 E100 E1L Demand Charge

The E100 E1L charge is designed to improve system utilisation by providing a peak demand cost signal, and to be reflective of the Network Costs associated with the shared network assets installed to supply the Connection. This allows consumers to control their costs by reducing their overall peak and signals the cost of additional network investment.

Definition of Chargeable Quantity

The E100 E1L Chargeable kVA Demands will be determined using the individual Connection's kVAh ½ hour volume data and is calculated by averaging the top 12 daily anytime maximum kVA demands (one peak per day) on a rolling 12 months basis. The E1L Chargeable kVA Demand will be either a minimum 100kVA or the actual average demand, whichever is the higher. In cases where kVA measured data is not available the kVA data will be determined from kW data using a representative power factor as determined by Powerco.

Where an E100 Connection changes Retailer the load history used to calculate the Chargeable kVA Demands will be transported with the Connection to the new Retailer.

For new E100 Connections the establishment Chargeable kVA Demand for the E1L charge will begin from the installation of the TOU metering, that is, if six months TOU history is available then the 12 peaks will be calculated using the six months data or if only one months TOU data is available the first month's invoice will have the 12 daily anytime maximum kVA demands occurring in the previous month.

E100 E1L monthly charge = E1L Charge (\$/kVA) x Chargeable KVA Demand

5.3 E1 CONNECTION GROUP

The Energy Volumes used to determine the E1 Group volume charges (ERD and ERN) and each Retailer's share of the E1 demand charge (ERL charge) at each GXP will be determined using GXP kWh ½ hr volume data. This will be based on NRM interim data (day 7) for the prior month available at the time of billing (for example the account rendered in December 2001 for the month of November 2001 would be based on GXP data from 1 November 2001 to 30 November 2001).

All demand and volume based quantities for the E1 Connection Group will be determined from data supplied to the NRM for volume reconciliation purposes and will be at the GXP (that is, installation metered volumes x applicable local network distribution loss factor). Should washups to quantities as part of the NRM washup cycle occur these will be charged, or rebated, as appropriate.

5.3.1 E1 ERD (Day) and ERN (Night) Volume Charge

The E1 ERD and ERN charges are designed to improve system utilisation by providing a cost signal for load shifting. Thereby allowing Retailers to control their costs by promoting and encouraging end consumers to shift their day usage into the less utilised night period.

For the determination of the energy volumes (kWh) the following time periods will be used:

Day is the sixteen-hour period from 07:00 hrs to 23:00 hrs daily.

Night is the eight-hour period from 23:00 hrs to 07:00 hrs daily.

E1 ERD monthly charges = ERD charge (¢/kWh) x Day Energy Volume (kWh)

E1 ERN monthly charge = ERN charge (¢/kWh) x Night Energy Volume (kWh)

5.3.2 E1 ERL Demand Charge

The E1 ERL charge is designed to improve system utilisation by providing a signal that reflects the transmission cost methodology as practicable as possible, given the consumer switches between Retailers. This signal allows Retailers to control their costs by encouraging end consumers to reduce their demand by shifting load from the Network peak demand times and thus provides a signal for cost of additional network investment due to increased peak demand. Regardless of the season Powerco is committed to providing a load control signal service where necessary, providing receivers are available, on a daily basis.

The Chargeable kW Demand for the E1 Connection Groups are calculated using the GXP ½ hour single anytime maximum kW demand associated with the E1 Connection Group at the GXP for the prior month determined by the billing date (for example, the account rendered in December 2001 for the month of November 2001 would be based on GXP data from 1 November 2001 to 30 November 2001)

The half hour quantities are derived by taking the GXP ½ hr gross load and subtracting off the E300 and E100 ½ hr loads, leaving the E1 group profiled load. The chargeable peak demand by Retailer is then determined by allocating the residual real power (kW) to retailers in proportion to their reconciled real energy (kWh) volumes.

Basing this peak demand charge on the previous month's volumes recognises Retailer consumer switching and is necessary in meeting the principle to treat all retailers fairly and equitably.

E1 ERL monthly charge = ERL charge (\$/kW) x Chargeable kW Demand

6. INVOICING OF RETAILERS

The invoice to each Retailer will detail each group of E1 Connections (per GXP), each E100 Connection and each E300 Connection supplied by that retailer. Connections contracted directly with Powerco on Network Connection Contracts will be billed directly.

7. SUMMARY OF MONTHLY CHARGES

The monthly charges for each E100 and E300 Connection and each group of E1 Connections supplied by each Retailer at each GXP will be as follows:-

E300 Connections

Network Assets Charge	E3A \$ per kVA x Installed Transformer Capacity (kVA) – minimum 300kVA level
Demand Charge	E3L \$ per kVA x Chargeable kVA Demand – Minimum monthly 300kVA charge

E100 Connections

Network Assets Charge	E1A \$ per ICP
Demand Charge	E1L \$ per kVA x Chargeable kVA Demand – Minimum monthly 100kVA charge

E1 Connections

Distribution Volume (kWh) Charges E1	ERD ¢/kWh x Day Energy Volume ERN ¢/kWh x Night Energy Volume Energy Volumes in kWh
Distribution demand Charge	ERL \$/kW x Chargeable kW Demand

The Line Charge structure and applicable rates are shown in Figure 2.

Fig 1.

LINE CHARGING ALLOCATION METHODOLOGY

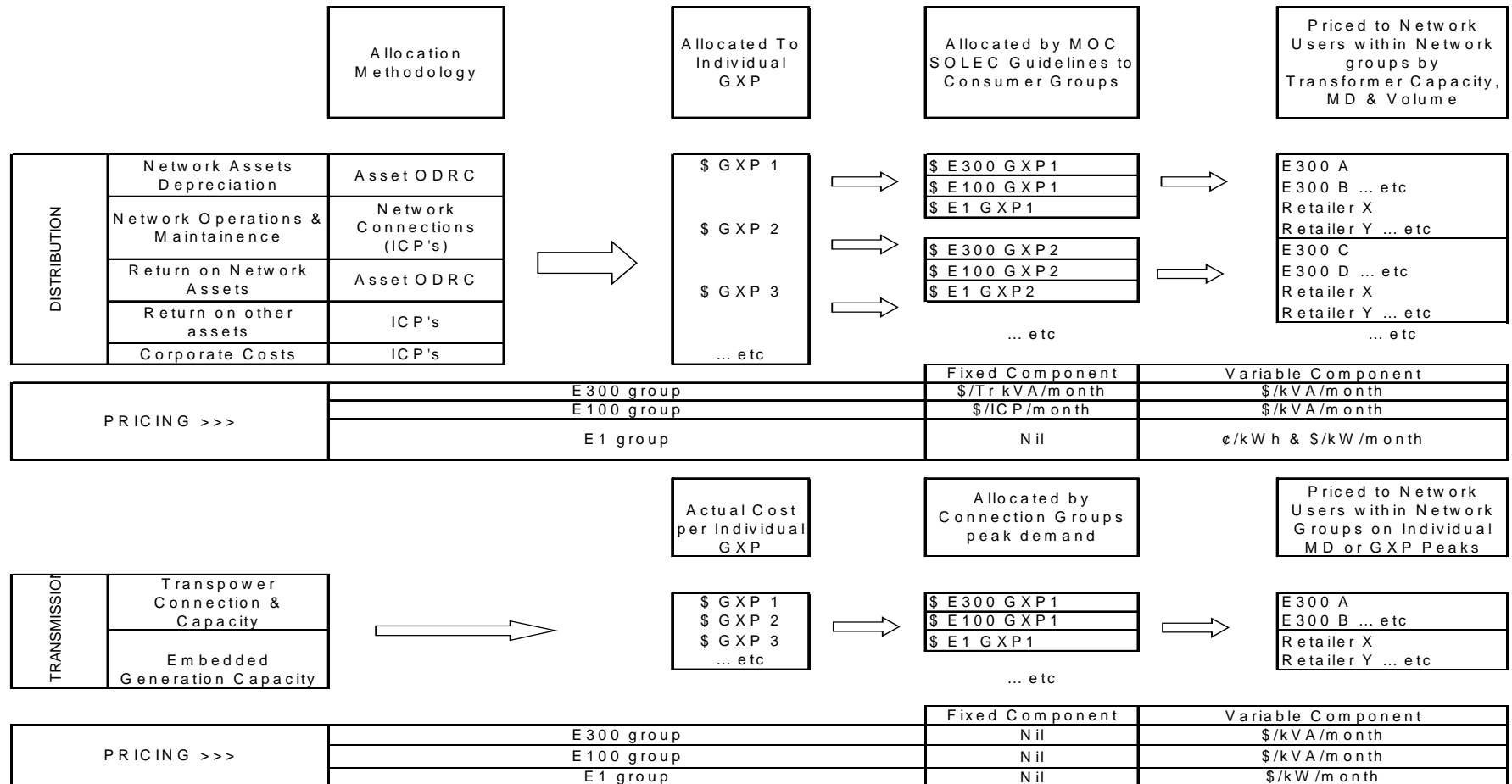


Fig 2.

Powerco Electricity Line Charges					
GST IS TO BE ADDED TO THESE PRICES					
Wholesale Charges for less than 100 kVA connections					
Effective Date: 1 November 2001					
Charge Code >>			ERD	ERN	ERL
GXP	GXP Grouping		E1 Volume Charges ¢/kWh		E1 Demand Charge \$/kW/month
			Day	Night	
Brunswick Wanganui Carrington Moturoa Stratford Huirangi	A		5.08	1.02	\$10.27
Opunake Waverley Marton Mataroa Ohakune Masterton Greytown Mangamaire	B		6.40	1.28	\$15.08
Bunnythorpe Linton	C		6.03	1.21	\$10.54
Hawera	D		6.40	1.28	\$12.86

Wholesale Charges for >100 kVA & >300kVA connections					
Effective Date: 1 November 2001					
Charge Code >>		E3A	E3L	E1A	E1L
		Installed Capacity >300kVA		Assessed Capacity >100kVA	
GXP	Connection Groups	E300 Network Assets Charge \$/kVA/month	E300 Demand Charge \$/kVA/month	E100 Network Assets Charge \$/ICP/month	E100 Demand Charge \$/kVA/month
Brunswick Wanganui	E	\$1.50 applies to all gxp groups	\$5.28	\$250.00 applies to all gxp groups	\$10.65
Carrington Moturoa Stratford Huirangi	A		\$6.99		\$11.15
Hawera	B		\$10.62		\$20.07
Opunake	D		\$16.31		\$20.82
Waverley	C		\$22.30		\$26.71
Marton	F		\$10.90		\$20.16
Mataroa Ohakune	G		\$23.28		\$27.91
Masterton Greytown	H		\$12.62		\$17.52
Mangamaire	J		\$8.63		\$12.77
Bunnythorpe Linton	I		\$8.36		\$10.94

Fig 3.

Schedule of costs and revenue components

Overall Line Service Costs and Revenue Requirement					
Network GXP	Cost of Capital \$'000	Depreciation \$'000	Admin, Operating & Maintenance Costs \$'000	Transmission Costs \$'000	Total Revenue required \$'000
Allocated by >>>		ODRC	ICP's		
Brunswick	2,511	789	1,999	1,408	6,708
Bunnythorpe	10,749	3,646	5,333	5,402	25,129
Carrington	3,969	1,095	3,109	3,579	11,752
Greytown	2,353	925	1,024	1,006	5,308
Huirangi	2,598	645	1,177	1,187	5,606
Hawera	3,407	944	1,625	3,113	9,090
Linton	2,869	896	2,695	2,621	9,081
Mangamaire	3,013	1,047	801	1,082	5,944
Masterton	5,008	1,547	2,707	2,779	12,041
Moturoa	1,317	400	1,409	1,122	4,249
Marton	2,119	668	1,073	1,614	5,475
Mataroa	1,944	528	575	931	3,978
Ohakune	441	144	216	300	1,102
Opunake	2,006	611	569	1,021	4,208
Stratford	4,757	1,412	1,398	1,346	8,913
Wanganui	2,027	685	1,725	1,764	6,202
Waverley	858	216	264	571	1,909
Totals all	51,946	16,200	27,700	30,847	126,693

Network GXP's	E300 CONNECTIONS					
	# ICP's	SOLEC E300 Distribution Cost Allocation	Total Distribution Revenue (000's)	E300 Transmission Cost Allocation	Total Transmission Revenue (000's)	Annual E300 demand (kVA)
Brunswick	18	9%	\$535	18%	\$258	102,222
Bunnythorpe	30	13%	\$2,266	13%	\$697	279,560
Carrington	28	17%	\$1,698	26%	\$924	309,945
Greytown	0	0%	\$0	0%	\$0	-
Huirangi	4	20%	\$489	20%	\$232	77,912
Hawera	7	20%	\$496	28%	\$876	145,281
Linton	21	10%	\$2,020	22%	\$584	234,183
Mangamaire	2	25%	\$313	27%	\$289	58,043
Masterton	12	13%	\$893	15%	\$418	103,168
Moturoa	8	6%	\$441	16%	\$184	61,668
Marton	4	8%	\$294	11%	\$173	36,038
Mataroa	2	14%	\$424	17%	\$162	22,886
Ohakune	0	0%	\$0	0%	\$0	-
Opunake	1	12%	\$378	14%	\$148	29,459
Stratford	8	12%	\$538	18%	\$245	82,271
Wanganui	12	16%	\$668	17%	\$308	121,930
Waverley	2	24%	\$328	30%	\$168	20,664
Totals	159		\$11,781		\$5,668	1,685,228

Network GXP's	E100 CONNECTIONS					
	# ICP's	SOLEC E100 Distribution Cost Allocations	Total Distribution Revenue (000's)	E100 Transmission Cost Allocation	Total Transmission Revenue (000's)	Annual E100 demand (kVA)
Brunswick	5	2%	\$115	2%	\$31	12,355
Bunnythorpe	57	8%	\$1,324	6%	\$340	136,483
Carrington	21	4%	\$391	3%	\$120	40,191
Greytown	2	2%	\$40	1%	\$10	2,560
Huirangi	0	0%	\$0	0%	\$0	-
Hawera	4	2%	\$115	1%	\$44	7,311
Linton	23	3%	\$460	4%	\$115	46,262
Mangamaire	1	1%	\$13	1%	\$7	1,309
Masterton	12	3%	\$349	3%	\$94	23,248
Moturoa	2	1%	\$39	1%	\$12	4,077
Marion	6	4%	\$163	3%	\$45	9,438
Mataroa	0	0%	\$0	0%	\$0	-
Ohakune	0	0%	\$0	0%	\$0	-
Opunake	0	0%	\$0	0%	\$0	-
Stratford	5	3%	\$115	3%	\$37	12,293
Wanganui	9	3%	\$146	2%	\$37	14,626
Waverley	0	0%	\$0	0%	\$0	-
Totals	147		\$3,271		\$893	310,154

Network GXP's	E1 CONNECTIONS					
	# ICP's	SOLEC E1 Distribution Cost Allocation	E1 Energy volumes (kWh)	Annual demands (kW)	Total E1 Distribution Revenue (000's)	Total E1 Transmission Revenue (000's)
Brunswick	11320	88%	85,849,793	229,867	\$4,468	\$1,456
Bunnythorpe	30172	79%	217,131,771	607,514	\$13,747	\$3,687
Carrington	17590	79%	160,233,460	355,869	\$8,128	\$2,254
Greytown	5807	98%	58,982,951	116,248	\$3,560	\$1,126
Huirangi	6676	80%	51,131,595	123,657	\$2,602	\$783
Hawera	9210	78%	84,797,005	196,260	\$5,326	\$1,466
Linton	15250	87%	186,184,668	499,730	\$11,185	\$3,033
Mangamaire	4544	74%	36,857,079	88,930	\$2,395	\$861
Masterton	15333	84%	149,441,152	294,341	\$9,021	\$2,850
Moturoa	7985	93%	55,343,456	134,266	\$2,852	\$850
Marion	6079	88%	56,657,583	124,093	\$3,619	\$1,202
Mataroa	3260	86%	29,625,649	66,396	\$1,893	\$643
Ohakune	1225	100%	9,616,776	21,750	\$613	\$211
Opunake	3229	88%	36,738,701	95,869	\$2,276	\$928
Stratford	7922	86%	79,774,977	197,338	\$4,044	\$1,250
Wanganui	9769	81%	81,726,288	224,748	\$4,307	\$1,424
Waverley	1494	76%	11,947,385	27,080	\$758	\$262
Totals	156865		1,392,040,290	3,403,956	\$80,794	\$24,286