Electricity retail cost index

Method

NZIER report to Electricity Authority

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Authorship

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1. Index of retail supply costs

This document describes the method for constructing a synthetic competitive retail electricity cost index.

The objective of the index is to measure changes in underlying cost components that affect retail electricity prices. The index is a guide to whether retail prices are changing due to changes in underlying costs or for some other reason.

1.1. Main components

The cost index is the sum of 6 costs which affect retail prices:

- Energy costs (EC)
- Transmission prices (TP)
- Distribution prices (DP)
- EA levy (EA)
- Retail overheads including metering (OH)
- GST rate (GST).

The components are added together to produce a hypothetical cost-based retail price in c/kWh. Like most price indices, the index is useful for understanding changes as opposed to levels.

These components are estimated for 149 offtake nodes.[1]

1.1.1. Calculated at node level

Price indices are calculated for each offtake GXP. Sources of variation are by: quarter (q), GXP (x), island (i), pricing year for transmission and distribution (y), financial (June) year for the EA, distribution company (EDB) and by transmission region (r).

The notional price by GXP and by quarter is calculated as:

$$P_{x,q} = \left(EC_{x,i,q} + TP_{x,q|y} + DP_{x|EDB,q|y} + OH_q + EA_q\right).(1 + GST)$$

1.1.2. Real and nominal price indices

A notional 'real' price (*P*^{r}) by GXP is also calculated by dividing the notional price by the ratio of the all groups CPI in the current quarter and the all groups CPI in the base, September 2010, quarter:

$$P^r_{x,q} = \frac{\left(EC_{x,i,q} + TP_{x,q|y} + DP_{x|EDB,q|y} + OH_q + EA_{q|y_j}\right).(1 + GST)}{\frac{CPI_q}{CPI_{q3,2010}}}$$

[1] These are the offtake nodes for which we have complete data series for all index components and excludes major direct connect nodes such as Tiwai and Glenbrook.

1.1.3. The index is consumption weighted

The 'prices' are aggregated, using a consumption weighted average, to yield an overall price index – or indices e.g. regional if desired. The consumption weights are presently fixed at share of MWh offtake by GXP in the year to September 2010 – the base period.[2] Thus the aggregate cost index is:

$$CI_q = \sum_{x}^{X} \frac{MWh_{x,base}}{MWh_{base}} . P_{x,q}$$

The calculations for the cost components and source data information are discussed below. Unit conversions (MW to kW) are excluded for simplicity. Some sources are noted, although most of these are obvious or are EA sources. Furthermore precise sources or data definitions are not essential in many cases (for example locations for price calculations in the list at the end) are not essential in many cases.

[2] Regional indices can also be calculated using regional cost shares as index weights.

2. Energy cost

2.1. Choice of energy costs to be measured

The energy cost component is based on an estimate of the underlying annual average cost of hedged energy used to serve customers on fixed price contracts of variable durations.

This approach takes account of premiums paid by retailers to avoid the risk of very high spot market prices and market views about expected energy costs. It abstracts away from the structure of the market to provide an estimate of energy costs to retailers who do not necessarily own generation assets.

The true underlying cost of energy to serve retail customers is not directly observable. In a workably competitive market retailers will bear short term and cyclical price risk in exchange for a premium over wholesale prices. The retailer's profitability will fluctuate, and might be negative in the short term, but should be positive on average over time. Retailers will set customers' prices given their expectations of the average wholesale market price over time. These expectations will reflect the structure of the market (e.g. capacity margins) and views on changing volatility and demand. Market expectations will be changing and adapting over time and are not directly observable.

We assume that underlying changes in energy costs can be proxied by movements in futures prices. In principle, trends in wholesale spot market energy prices could be used to gauge changes in the underlying cost of energy. However this approach needs very long time series. That means the resulting estimates would not be useful for gauging shorter term changes in the market and the underlying cost of energy.

2.2. Estimation methods

Estimates of energy costs are constructed for both nodes for which futures contracts are available: Otahuhu and Benmore.

We use ASX futures contracts as these provide a single consistent estimate of the underlying market value of hedged energy.

The ASX information comes with the down side that the market has only been operating since mid-2009 and trading volumes are quite limited for the first two years of trading. The limited trading periods means that the number of periods used to calculate averages (T) varies by contract quarter (q).

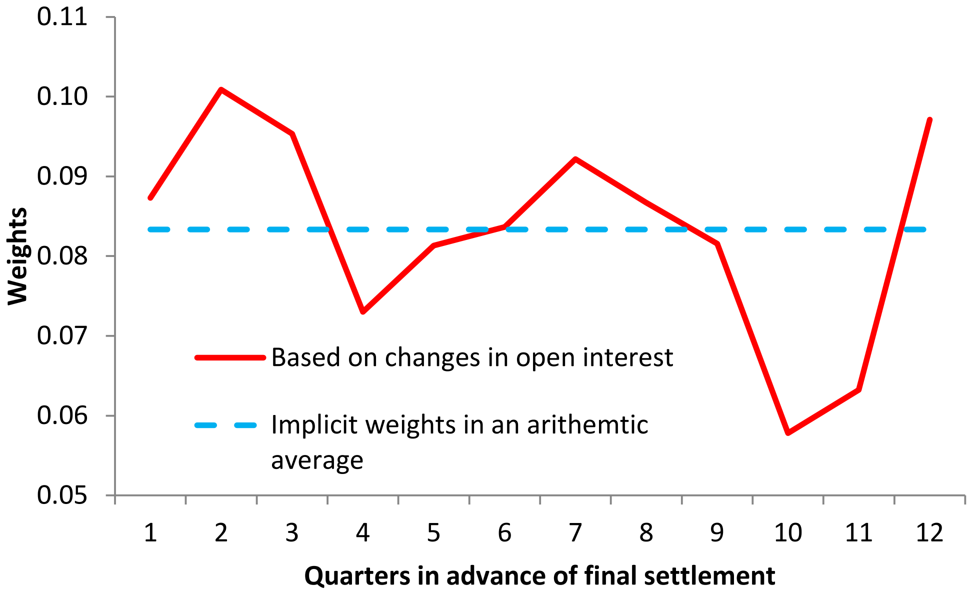
At the same time, using the ASX futures means that our estimates of the underlying cost of energy will reflect recent improvements and past deficiencies in hedge market liquidity in New Zealand. The timing of these improvements and deficiencies affect the underlying cost of retailing electricity.

Our use of the arithmetic average of futures prices applies equal weight to all prices. In principle, some trading periods should be given more weight than others depending on factors such as the term structure of retailers' portfolios of contracts and prices and the preferences of their customers.

In principle, we should apply a low weight to short term futures prices (within one or two quarters of the end of the contract quarter). This is because we are most interested in market fundamentals rather than one off market conditions. Short term prices will reflect realised market conditions, such as actual hydro inflows, rather than just fundamental expectations of prices and price risk.

We analysed an alternative weighting schema based on weighting futures prices by daily changes in open interest on futures contracts. This weighting scheme puts considerably different emphasis on different points in the term structure of futures contracts (see Figure 1). But, this approach did remarkably little to change the estimated energy cost series since the fluctuations in weights in Figure 1 counterbalanced each other. We chose to use equally weighted or arithmetic averages for reasons of simplicity and transparency.[3]

Figure 1 Futures contract weighting by change in open interest



Source: NZIER

Our estimates of unit energy cost based on futures prices, at Benmore and Otahuhu, are used to construct estimates of quarterly energy costs at different grid offtake nodes by multiplying energy costs by offtake volumes (to account for costs reflecting seasonal variations in consumption which differ by location) and location factors which are the ratio of average spot market nodal prices to the prices at the Benmore and Otahuhu reference nodes. We use the average location factor from 2002 to 2013 to account for fundamental locational price differences.

Underlying energy cost (*EC*) in quarter *q* at reference node *i* is the arithmetic average of all (*t* through *T*) forward (FP) prices for quarter *q*[4]:

[3] More sophisticated methods of estimating the underlying series (such as the Kalman filter) might lead to improvements to our weighting method Such methods are useful since they incorporate additional observations about the state of the market such as capacity margins, rather than relying solely on futures prices.

[4] When the index was constructed quarterly forward prices at Benmore and Otahuhu were the only readily available (ASX) prices.

$$EC_{i,q} = \frac{\sum_{t=1}^{T} FP_{t,i,q}}{T}$$

Reference nodes are Benmore and Otahuhu. FP is quarterly ASX forward price data. Data is sourced from the EA.

Energy cost for each GXP (x) is calculated using the reference node in its island and scaling the price up or down according to the ratio of the 10 year average historical wholesale spot price at x_i in island *i* to the average historical wholesale spot price at the reference node for island – i.e. a location factor:

$$LF_{x,i,T} = \frac{\frac{\sum_{t}^{T} p_{x,i}}{T}}{\frac{\sum_{t}^{T} p_{x=i,i}}{T}}$$

The final Energy Cost calculation includes consumption weighting to avoid giving any weight to prices where a GXP has zero demand. The underlying energy cost component for each GXP is:

$$EC_{x,i,q} = \frac{LF_{x,i,T} \cdot \sum_{q-3}^{q} EC_{i,q} . MWh_{x,i,q}}{\sum_{q-3}^{q} MWh_{x,i,q}}$$

Price data and MWh data are sourced via the Electricity Authority.

3. Transmission charges

3.1. Interconnection and connection charges

Transmission charges are estimated based on published pricing methodologies and revenue data.

Interconnection charges are applied to nodes according to published interconnection rates and shares of regional peaks during the capacity measurement period (which is the year ended September immediately preceding the pricing year).

Connection charges are applied based on dividing connection revenue by offtake volume by node. This is a rough approximation that is reasonable since the connection charges are small. Calculating actual connection charges would be very time consuming because they are based on a range of physical attributes of connection assets which vary by node.

We ignore contract rates and discounts offered to some customers by Transpower.

We calculate quarterly transmission charges based on implied annual transmission charges at each node divided by annual consumption (i.e. $/MWh). This charge is held constant for all quarters in the transmission pricing period (which runs from the June to March quarters). By doing this we assume that distributors have perfect knowledge of forthcoming annual consumption at each node and fully pass through connection and interconnection charges in every period. In reality, transmission charges may be over- or under-recovered in any period but this is not material for our purposes.

3.2. Estimation method

Transmission charges are modelled in two pieces:

- the RCPD formula is used to allocate interconnection charges by GXP
- connection charges allocated on a pro-rata MWh basis

The RCPD calculation is simply the share of a GXPs demand in its regions coincident peak demand, multiplied by the region's coincident peak demand and the interconnection rate (*IR*) applying for that pricing year (*y*):

$$IC_{x,r,y} = IR_y . \frac{\sum_{j=1}^{N_r} MW_{x,j}}{\sum_{j=1}^{N_r} MW_{r,j}} . \frac{\sum_{j=1}^{N_r} MW_{r,j}}{N_r}$$

Where we denote the usual 4 regions as r (= UNI, LNI, USI, LSI), pricing years y (= April to March) and capacity measurement periods consisting for the *j* through *N* periods of highest demand in the region within the capacity measurement period (September to August).

This calculation is an approximation to actual charges because it does not account for actual contract terms including aggregation of GXPs for the purposes of charging. This method tends to overstate charges to GXPs with industrial load and understate charges for other GXPs. It also does not consider the methods by which distribution companies pass charges through to retailers.

The interconnection rate is the rate calculated and applied by Transpower – as opposed to the rate that would be calculated if it had been modelled directly based on the full pricing formula.[5]

The pro rata connection charge (C) is 75% of connection revenue (CR) for the pricing year, published by Transpower, divided by average annual total NZ MWh consumption for the previous four years (grid offtake)[6]:

$$C_{x,y} = \frac{0.75CR}{0.25\sum_{y}^{y-3} MWh_{NZ,y}}$$

The 75% adjustment is an approximation to the share of connection charges paid by load or by EDBs. It is based approximately 75% of grid connection points (by count) are for offtake, Connection charges faced by generators are assumed to find their way into wholesale energy costs.

Prices are converted to a per quarter MWh equivalent by dividing the charge by the sum of the demand (MWh) in the first quarter of the pricing year and the previous 3 quarters. This price is then fixed for each quarter of the pricing year. The transmission for quarters in a given pricing year is then:

$$TP_{x,q|y} = \frac{IC_{x,y} + C_{x,y}}{\sum_{\bar{q}}^{\bar{q}-3} MWh_{x,\bar{q}}}$$

5 https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/year-specific-data-2013-14.pdf

6 The choice of a multi-year average is to try to avoid exacerbating demand/volume effects which come through when later we construct per MWh price measures.

4. Distribution charges

Estimated distribution charges are based on reported gross income for each EDB divided by an EDB's volume supplied to customers.

Including variation in charges across EDBs (i.e. by location) has the benefit of reflecting variable underlying costs of serving customers in sparsely populated areas or with many connections relative to volumes consumed (i.e. mix of residential versus commercial and industrial demands). This underlying variation is quite wide.

Not all variation is captured by this approach. We abstract from the discretion that EDB's have in terms of charging different customers different rates. Our approach also assumes that charges applied by a given operator are the same across all nodes. This will not be the case because some nodes serve many small customers and some nodes serve many large customers. However, this will not affect our overall results to any material degree because of the regional concentrations of EDBs.

4.1. Estimation Method

EDB charges are based on actual published data where available. This data is gross revenue (*GR*) by EDBs divided by EDB volumes available from the Commerce Commission – although slow to be collected and updated.

Prices net of transmission charges are modelled by subtracting the modelled transmission prices.

Prices from EDB charges are applied in the same way as for transmission prices with prices changing at the start of a June quarter 'pricing year' and remaining constant through the year.

Each GXP is assigned a single EDB and that GXP faces the EDB's modelled distribution price per MWh (*DP*):

$$DP_{x|EDB,q|y} = \frac{GR_{EDB,y}}{MWh_{EDB,y}} - TP_{x,q|y}$$

No attention is paid to intra-network or intra-company prices or tariff differences.[7]

Estimates or quarter-specific adjustments typically need to be made for recent quarters where actuals are not available. There is no single method for this. Adjustments or estimates must be decided on a case by case basis e.g.

- published rates of allowed revenue increase (e.g. CPI) provided by the Commerce Commission
- Most recently prices for the year ended April 2014 included starting price adjustments published by the Commerce Commission.

[7] This is deliberate. It avoids accounting for EDB decisions on pricing which may or may not be cost related.

5. Electricity Authority levy

The EA levy is a constant annual (pro rata) per MWh charge based on data published by the EA. Levy rates (*LR*) are held constant over a June year (y_j).

We assume all levy revenue is a factor in retail costs and divide levy revenue (*LR*) by annual volume (MWh) to yield a per MWh price component. The data is from e.g. annual reports for actuals the calculations for the 'price' of the EA levy are are simply:

$$EA_{q|y_j} = \frac{LR_{y_j}}{MWh_{y_j}}$$

Where actuals are not available estimates are used. These are based on weighted average changes in all levy rates – with weights being cost shares (s) by cost category and participant.

$$EA_{q|y_j} = EA_{q|y_j-1} \cdot \sum_{p}^{P} \sum_{c}^{C} s_{c,p,y_j-1} \cdot \frac{lr_{c,p,y_j}}{lr_{c,p,y_j-1}}$$

Source data are either published or invoiced rates depending on data available – the levy also being subject to periodic revisions and reconciliations.

The EA levy was originally assumed to remain constant as it is such a small cost it is not very relevant. The above calculations were introduced in recognition of potential charges of self-interest/bias in not tracking changes in the EAs own costs and their effects on retail prices. The above calculations are not complicated so the levy is not too costly to include.

6. Overheads and meter costs

6.1. Approach and rationale

Overheads are calculated for the base quarter – September 2010 – and then inflated by general inflation in Producer Input Prices for all industries.

The benchmark quarter value is the average margin observed in recent years (1.61 c/kWh) divided by the average underlying energy and lines costs (15.35 c/kWh) to yield a margin over energy and lines costs of 10.5%. This margin is then applied to the base period average energy and lines cost (13.4 c/kWh) to yield a margin wedge of 1.4 c/kWh in the September 2010 quarter.

This margin is only used to gauge the order of magnitude of margins and hence the weight that margins should take in the overall price index. It is not a precise measure. Volumetric (c/kWh) margins vary considerably across companies because, for example, some retailers have larger customers than others. Our estimates suggest Genesis has higher than average margins on a volumetric basis but smaller than average margins on a per-customer (ICP) basis.

For most companies and time periods the margin calculation only includes operating costs and does not include any return on capital. This is because we could not find any information on the assets of the retail business.

We have chosen not to infer capital costs for companies without asset information because we cannot be sure how well-defined retail assets are in those cases where they have been reported. Integrated generator-retailers will have overheads and assets which are shared between the retail and wholesale functions and it is not clear how the line has been drawn even where retail assets have been reported.

Our approach is thus only an approximation to an order of magnitude and primarily uses PPI inflation to infer margin cost changes. In our view this is reasonable because alternative more detailed methods would be costly and time consuming to produce which is not warranted because margins are not a large proportion of costs. Most importantly, detailed data on actual margins would cause the index to reflect output prices and profits rather than a changes in costs.

6.1.1. Data and estimation

Retail overheads implicitly include cost of capital, labour costs, and operating expenditure. To estimate a competitive level of retail overheads we analysed major generator-retailers' annual reports.

The reason we use the data of major generator-retailers is that this information is publicly available.

Our estimate of overheads is an average of cost estimates from a series of intermittent observations. The patchiness of the data reflects differences in the kinds of information reported by retailers and changes in the way information is reported. In recent years it has become increasingly difficult to find information relevant to retail margins because retailer-generators are increasingly reporting their energy businesses in a single reporting category where they used to report wholesale and retail segments separately.

The data used is replicated in Table 1 below.

In the case of Meridian and Mighty River Power we had sufficient information to build up some estimates of capital costs. Capital costs were estimated based on asset value and a weighted average cost of capital (WACC) of 8.9%. This WACC is the average of two WACC values. One is from the capital valuation of Meridian conducted by the Macquarie for the Crown Ownership Monitoring Unit (COMU) in 2011. The other is from a report to meridian by PWC which was also considered by COMU.

6.1.2. Accounting for metering costs

We add the costs of metering to retail overheads. For some companies metering is an operating cost. For others, metering services provide a revenue stream. We have chosen to explicitly account for metering costs because it is a non-trivial cost faced by a small retailer which will affect retail prices.

The main source of data for meter costs is, de facto, the cost of metering reported in Contact Energy's accounts. Relying on data almost solely from a single retailer is not ideal but is unavoidable. We also include a 2009 observation on metering costs from Meridian's annual report which shows metering costs of 0.17c/kWh. T

Contact's information is a reasonable choice because Contact's metering is subject to internal charging and thus costs are subject to scrutiny of competing interests within the company. Contact's internal metering costs have averaged 0.28 c/kWh of energy sold to retail customers in the past 4 financial years.

Overall, average metering costs in the data are 0.26c/kWh. This value is added to the benchmark margin value for the September 2010 quarter and PPI inflation is then applied to the combined cost of metering and retail overhead.

The PPI inflation measured used is the annual average change in the PPI. The overhead (*OH*) value is held constant for all GXPs:

$$OH_q = OH_{q3,2010} \cdot \frac{\sum_{q-3}^{q} PPI_q}{\sum_{q4,2009}^{q3,2010} PPI_q}$$

Table 1 Margin data

		Retail Assets ($)	Employee costs ($)	Other opex ($)	Retail MWh	Meter costs ($)	Return on Assets c/kWh	Margin c/kWh	Meter cost c/kWh	ICPs	Benchmark margin per ICP ($2010)
Meridian	Jun-09	188,454,000		61,800,000	7,763,000	13,000,000	0.021	1.01	0.17	232,163	470.4
Meridian	Jun-10	178,617,000	24,400,000	44,800,000	7,740,000		0.020	1.10		243,670	446.9
Meridian	Jun-11	211,097,000	25,000,000	41,800,000	7,870,000		0.024	1.09		282,152	392.4
Meridian	Jun-12	194,330,000	25,600,000	49,600,000	7,599,000		0.023	1.22		293,206	364.6
Meridian	Jun-13		28,200,000	58,000,000	7,522,000		-	1.15		277,192	381.8
Genesis	Jun-10				6,378,000		-			521,565	172.0
Genesis	Jun-11		32,350,000	103,228,000	5,705,000		-	2.38		533,749	150.4
Genesis	Jun-12		29,119,000	110,342,000	5,429,000		-	2.57		532,393	143.5
Genesis	Jun-13		24,964,000	117,540,000	5,354,000		-	2.66		547,532	137.6
Contact	Jun-09				7,703,000					489,904	221.2
Contact	Jun-10				7,674,000	20,992,000	-	1.50	0.27	489,387	220.6
Contact	Jun-11			90,794,000	8,254,000	22,032,000	-	1.50	0.27	464,025	250.2
Contact	Jun-12			91,080,000	8,280,000	22,752,000	-	1.50	0.27	459,486	253.5
Contact	Jun-13				8,277,000	26,000,000	-	1.50	0.31	454,340	256.3
MRP	Jun-09					37,331,000				409,313	-
MRP	Jun-10	208,836,000		118,077,000	8,254,000	45,811,000	0.022	1.65		436,575	266.0
MRP	Jun-11	169,890,000		117,004,000	7,446,000	60,903,000	0.020	1.77		400,114	261.8
MRP	Jun-13					64,062,000				395,245	-

7. Locations

A list of locations used to calculate charges is provided below. Changes to (inter alia) grid configuration means some of these locations (GXPs) are no longer updated.

Note that use of different locations will change some of the calculated cost components – particularly transmission charges.

Island	Reg	EDB	GXP
SI	South Canterbury	ALPE	ABY0111
SI	Canterbury	ORON	ADD0111
SI	Canterbury	ORON	ADD0661
NI	North Isthmus	UNET	ALB0331
NI	North Isthmus	UNET	ALB1101
SI	West Coast	ORON	APS0111
SI	Canterbury	EASH	ASB0331
SI	Canterbury	EASH	ASB0661
SI	Canterbury	MPOW	ASY0111
SI	Otago/Southland	OTPO	BAL0331
SI	Nelson/Marlborough	MARL	BLN0331
NI	Auckland	COUP	BOB0331
NI	Auckland	COUP	BOB1101
SI	Otago/Southland	ALPE	BPD1101
NI	Central	POCO	BPE0331
SI	South Canterbury	WATA	BPT1101
NI	North Isthmus	NPOW	BRB0331
NI	Central	POCO	BRK0331
SI	Canterbury	ORON	BRY0111
SI	Canterbury	ORON	BRY0661
NI	Waikato	WAIP	CBG0111
SI	West Coast	ORON	CLH0111
SI	Otago/Southland	DUNE	CML0331
SI	Canterbury	ORON	COL0111
NI	Wellington	CKHK	CPK0111
NI	Wellington	CKHK	CPK0331
NI	Taranaki	POCO	CST0331
NI	North Isthmus	NPOW	DAR0111
SI	West Coast	WPOW	DOB0331
NI	Central	SCAN	DVK0111
NI	BOP	HEDL	EDG0331
SI	Otago/Southland	TPCO	EDN0331
NI	Hawkes Bay	HAWK	FHL0331
SI	Otago/Southland	DUNE	FKN0331
NI	Wellington	CKHK	GFD0331

NI	Hawkes Bay	EAST	GIS0501
SI	Otago/Southland	TPCO	GOR0331
SI	West Coast	WPOW	GYM0661
NI	Wellington	POCO	GYT0331
NI	Waikato	WAIK	HAM0111
NI	Waikato	WAIK	HAM0331
NI	Wellington	CKHK	HAY0111
NI	Wellington	CKHK	HAY0331
NI	North Isthmus	UNET	HEN0331
NI	North Isthmus	UNET	HEP0331
NI	Waikato	POCO	HIN0331
SI	West Coast	WPOW	HKK0661
SI	Canterbury	ORON	HOR0331
SI	Canterbury	ORON	HOR0661
NI	Waikato	LINE	HTI0331
NI	Taranaki	POCO	HUI0331
NI	Taranaki	POCO	HWA0331
SI	Otago/Southland	DUNE	HWB0331
SI	Otago/Southland	DUNE	HWB0332
SI	Otago/Southland	ELIN	INV0331
SI	Canterbury	ORON	ISL0331
SI	Canterbury	ORON	ISL0661
SI	Canterbury	MPOW	KAI0111
NI	BOP	HEDL	KAW0111
NI	North Isthmus	NPOW	KEN0331
SI	Nelson/Marlborough	TASM	KIK0111
NI	Waikato	POCO	KIN0111
NI	Waikato	POCO	KIN0331
NI	BOP	POCO	KMO0331
NI	Waikato	POCO	KPU0661
SI	West Coast	WPOW	KUM0661
NI	Wellington	CKHK	KWA0111
NI	Waikato	VECT	LFD1101
NI	Waikato	VECT	LFD1102
NI	Central	POCO	LTN0331
SI	West Coast	TASM	MCH0111
NI	Auckland	WAIK	MER0331
NI	Central	POCO	MGM0331
NI	Central	ELEC	MHO0331
NI	Wellington	CKHK	MLG0111
NI	Wellington	CKHK	MLG0331
SI	Canterbury	ORON	MLN0661
SI	Canterbury	ORON	MLN0664
NI	Auckland	VECT	MNG0331

NI	Auckland	VECT	MNG1101
SI	Nelson/Marlborough	TASM	MOT0111
NI	North Isthmus	NPOW	MPE0331
SI	Nelson/Marlborough	TASM	MPI0661
NI	Wellington	POCO	MST0331
NI	BOP	POCO	MTM0331
NI	Central	POCO	MTN0331
NI	North Isthmus	NPOW	MTO0331
NI	Central	POCO	MTR0331
SI	Otago/Southland	TPCO	NMA0331
NI	Central	LINE	NPK0331
SI	Otago/Southland	OTPO	NSY0331
SI	Otago/Southland	WATA	OAM0331
NI	Central	LINE	OKN0111
NI	Central	LINE	ONG0331
NI	Taranaki	POCO	OPK0331
SI	West Coast	BUEL	ORO1101
SI	West Coast	BUEL	ORO1102
SI	West Coast	WPOW	OTI0111
NI	BOP	HAWK	OWH0111
NI	Auckland	VECT	PAK0331
SI	Otago/Southland	OTPO	PAL0331
SI	Canterbury	ORON	PAP0111
SI	Canterbury	ORON	PAP0661
NI	Auckland	VECT	PEN0221
NI	Auckland	VECT	PEN1101
NI	Wellington	CKHK	PNI0331
NI	Wellington	ELEC	PRM0331
NI	Hawkes Bay	HAWK	RDF0331
SI	West Coast	WPOW	RFN1101
SI	West Coast	WPOW	RFN1102
NI	Auckland	VECT	ROS0221
NI	BOP	HAWK	ROT0111
NI	BOP	HAWK	ROT0331
SI	Canterbury	MPOW	SBK0331
SI	Otago/Southland	DUNE	SDN0331
SI	Canterbury	ORON	SPN0331
SI	Canterbury	ORON	SPN0661
SI	Nelson/Marlborough	TASM	STK0331
SI	Otago/Southland	ALPE	STU0111
NI	North Isthmus	UNET	SVL0331
NI	Auckland	VECT	TAK0331
NI	BOP	POCO	TGA0111
NI	BOP	POCO	TGA0331

SI	South Canterbury	ALPE	TIM0111
SI	South Canterbury	ALPE	TKA0331
NI	BOP	HEDL	TKH0111
NI	Wellington	CKHK	TKR0331
NI	BOP	POCO	TMI0331
SI	South Canterbury	ALPE	TMK0331
NI	Waikato	WAIP	TMU0111
NI	WNST	LINE	TNG0111
NI	BOP	HAWK	TRK0111
NI	Hawkes Bay	EAST	TUI0111
NI	Waikato	WAIK	TWH0331
SI	South Canterbury	ALPE	TWZ0331
NI	Wellington	CKHK	UHT0331
NI	BOP	HEDL	WAI0111
NI	Central	SCAN	WDV0111
NI	North Isthmus	UNET	WEL0331
NI	Central	POCO	WGN0331
NI	Waikato	POCO	WHU0331
NI	Wellington	CKHK	WIL0331
NI	Auckland	VECT	WIR0331
NI	Waikato	POCO	WKO0331
SI	Canterbury	MPOW	WPR0331
SI	Canterbury	MPOW	WPR0661
SI	West Coast	BUEL	WPT0111
NI	Hawkes Bay	EAST	WRA0111
SI	Otago/Southland	WATA	WTK0331
NI	Hawkes Bay	HAWK	WTU0331
NI	Taranaki	POCO	WVY0111