TPM options working paper and related documents – revisions to indicative modelling

30 July 2015

1. Introduction

The Electricity Authority (Authority) published a working paper 'Transmission pricing methodology review: TPM options' (the TPM options working paper) on 16 June 2015. The Authority published a 'Companion paper describing the detail of the deeper connection charge' (the deeper connection companion paper) at the same time. The Authority published two further modelling documents on 26 June 2015.

The working paper described three options (the Base Option, Base Option + LRMC and Base Option + SPD) and two applications (A and B).

The working paper, and associated documents, provided some modelling in order to assist stakeholders to understand the estimated or indicative impact of the options under each application. The papers set out that this modelling was subject to various assumptions – including, but not limited to:

- the design of the various charging options, including the allocators used, and key parameters (such as the Herfindahl-Hirschman Index (HHI) cut-off used in the application of the deeper connection charge)
- the pattern of investment in, and operation of, generation, load and transmission
- the way in which participants respond to the various charging options
- the timeframe over which the new charges are put in place. The modelling is for a 2017-19 scenario, but any change to the TPM is unlikely to affect transmission charges until 2019 at the earliest.

The deeper connection charge has a role under all options and both applications described in the working paper. The Authority has carried out further analysis of the deeper connection charge, and identified some errors and issues in the modelling of the deeper connection charge that has been carried out to date. These errors and issues relate to:

- a bug in calculating the upstream trace results for generators
- the treatment of losses in the flow tracing
- the aggregation of some North Island load nodes to participants for the purpose of calculating HHI
- the allocation of costs between participants for some substation nodes that are deeper connection assets for both load and generation
- the exclusion of some load nodes, at which injection occurs, in the generation flow trace. These include some nodes at which there is wind generation.

To ensure transparency around potential financial impacts, this paper updates the previously published modelling results to address these issues.

(Graphs, and comments on graphs, in the options working paper and the companion papers have not been updated.)

The remainder of this document is set out as follows:

Section	Contents	Source document
2	• Modelled changes in charges, relative to the status quo • Modelled incidence of charges • Modelled incidence of charges, on a fully variabilised basis • Effect of options on prices faced by residential consumers, in c/kWh terms • Effect of options on prices faced by residential consumers, in % terms	TPM options working paper (https://www.ea.govt.nz/dms document/19472, p128-137)
3	• Modelled incidence of deeper connection charges • Modelled incidence of deeper connection charges, on a fully variabilised basis	Deeper connection companion paper (https://www.ea.govt.nz/dms document/19471, p38-40)
4	• Modelled charges on residential load, as $ per year for a typical household • Comparison between the figures above and those in Table 15b of the options working paper (which showed average charges per ICP)	'Modelled charges on residential load' document (https://www.ea.govt.nz/dms document/19504, p3-4)
5	• Modelled charges on mass-market load, under four cap and transition options • Modelled charging rates, under four cap and transition options	'Caps and transitions' document (https://www.ea.govt.nz/dms document/19505, p5-7)

For clarity, the modelling included in this paper (and in the papers published previously) provides the estimated / indicative impact of each TPM option under applications A and B, and relies on the assumptions set out in the relevant documents.

The actual impact of any changes to the transmission pricing regime will depend on the guidelines published by the Authority (if any), and on how Transpower gives effect to those guidelines in drafting a new TPM.

2. TPM options working paper

Revised versions of Tables 14, 15a and 15c of the document are provided below.

Table 14: Annual change in charges to generation and load, relative to the status quo, for each option under Application A, in $M p.a. terms

	Base Option	Base Option + LRMC	Base Option + SPD
NI generation	24	24	21
SI generation	-47	-42	-61
UNI mass-market load	140	138	149
LNI mass-market load	-15	-18	-8
SI mass-market load	-27	-26	-29
NZAS	-56	-56	-52
Other major industrials	-18	-18	-16

In $/MWh terms:

	Base Option	Base Option + LRMC	Base Option + SPD
NI generation	0.9	0.9	0.8
SI generation	-2.8	-2.6	-3.7
UNI mass-market load	13.7 (1.37 c/kWh)	13.5	14.5
LNI mass-market load	-1.3	-1.6	-0.7
SI mass-market load	-2.8	-2.7	-3.1
NZAS	-11.1	-11.0	-10.3
Other major industrials	-4.1	-4.1	-3.5

Note: The figures above refer to:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for mass-market load.*

Table 15a: Modelled incidence of charges ($M per year)

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
EDBs					
Alpine Energy	7.89	7.78	7.78		10.92
Aurora Energy	18.71	18.36	17.91		20.77
Buller Electricity	1.69	1.84	1.70		1.65
Counties Power	12.51	12.40	12.37		7.14
Eastland Network	6.49	6.40	6.48		5.61
Electra	10.38	10.21	10.31		7.30
Electricity Ashburton	4.83	5.20	4.75		4.04
Horizon	5.06	5.04	5.30		2.78
Mainpower	8.10	7.93	7.77		9.48
Marlborough Lines	10.57	11.00	10.37		6.61
Network Tasman	11.58	11.66	11.27		11.48
Network Waitaki	2.80	2.79	2.72		3.70
Northpower	35.98	35.76	36.79		16.54
Orion	42.17	43.42	41.12		67.93
Powerco	79.22	78.09	80.68		74.31
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	16.10	15.57	15.91		21.86
Scanpower	1.44	1.41	1.47		1.62
The Lines Company	4.88	4.85	4.83		4.03
Top Energy	13.05	12.95	12.87		4.76
Unison *(incl Centralines)*	28.54	28.10	29.27		33.79
Vector	285.18	283.85	291.10		178.43
Waipa Power	4.96	4.83	5.21		6.67
WEL	19.07	18.86	19.53		21.55
Wellington Electricity	41.78	40.80	43.71		59.03
Westpower	9.08	9.18	9.00		2.39
Aggregate	682.07	678.29	690.23		584.40

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
Generators					
Contact	42.40	42.02	40.50		27.59
Fonterra *(Whareroa)*	0.18	0.18	0.26		0.18
Genesis	7.82	6.30	7.40		7.19
Meridian	43.46	48.20	32.94		92.19
Mokai JV	0.57	0.62	0.32		0.00
MRP	5.05	6.27	4.62		0.00
NAP JV	1.64	0.98	1.63		0.00
Ngatamariki	0.86	0.86	0.87		0.00
NZ Wind Farms	0.00	0.00	0.00		0.00
Pioneer	0.61	0.56	0.55		0.53
Todd	0.70	0.61	0.65		0.00
Trustpower	4.91	5.11	3.95		2.74
Aggregate	108.21	111.71	93.70		130.42
Major industrials					
CHH	1.37	1.36	1.84		4.41
Daiken MDF	0.19	-0.10	0.25		0.89
Kiwirail	0.16	0.15	0.20		0.47
Methanex	0.18	0.18	0.24		0.55
Norske Skog	1.10	1.35	1.03		0.00
NZ Steel	1.65	1.80	2.36		8.85
NZAS	6.86	7.08	10.90		63.22
Pacific Steel	1.24	1.26	1.57		3.62
PanPac	1.18	1.17	1.41		2.20
Rayonier	0.39	0.38	0.44		0.73
Winstones	0.39	0.38	0.62		3.63
Aggregate	14.73	15.01	20.89		88.58

Table 15c: Modelled incidence of charges, on a fully variabilised basis ($/MWh)

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
EDBs					
Alpine Energy	10.3	10.2	10.2		14.3
Aurora Energy	13.4	13.1	12.8		14.9
Buller Electricity	14.5	15.8	14.6		14.1
Counties Power	25.8	25.5	25.5		14.7
Eastland Network	21.0	20.7	21.0		18.2
Electra	22.0	21.6	21.9		15.5
Electricity Ashburton	8.5	9.1	8.4		7.1
Horizon	9.6	9.6	10.1		5.3
Mainpower	15.3	15.0	14.7		17.9
Marlborough Lines	26.7	27.8	26.2		16.7
Network Tasman	14.0	14.1	13.7		13.9
Network Waitaki	11.3	11.3	11.0		14.9
Northpower	34.2	34.0	35.0		15.7
Orion	12.7	13.0	12.4		20.4
Powerco	17.3	17.1	17.6		16.3
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	10.7	10.4	10.6		14.5
Scanpower	15.6	15.3	15.9		17.6
The Lines Company	16.0	15.9	15.8		13.2
Top Energy	37.1	36.8	36.5		13.5
Unison *(incl Centralines)*	15.4	15.2	15.8		18.3
Vector	31.9	31.7	32.5		19.9
Waipa Power	12.5	12.2	13.1		16.8
WEL	14.4	14.3	14.8		16.3
Wellington Electricity	15.5	15.2	16.2		21.9
Westpower	30.8	31.1	30.5		8.1
Generators					
Contact	3.9	3.8	3.7		2.5
Genesis	1.0	0.8	0.9		0.9
Meridian	3.7	4.1	2.8		7.9

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
Mokai JV	0.6	0.7	0.3		0.0
MRP	0.9	1.2	0.9		0.0
NAP JV	1.4	0.8	1.4		0.0
Ngatamariki	1.3	1.3	1.4		0.0
Todd	1.2	1.0	1.1		0.0
Trustpower	2.5	2.6	2.0		1.4
Major industrials					
CHH	2.2	2.1	2.9		7.0
Daiken MDF	2.6	-1.3	3.5		12.1
Kiwirail	4.1	3.7	5.2		12.0
Methanex	4.0	3.9	5.3		12.0
Norske Skog	2.1	2.6	2.0		0.0
NZ Steel	1.6	1.7	2.3		8.6
NZAS	1.3	1.4	2.1		12.4
Pacific Steel	6.1	6.2	7.8		17.9
PanPac	2.3	2.3	2.7		4.2
Rayonier	6.9	6.6	7.8		12.7
Winstones	1.4	1.4	2.2		13.0

Note: The figures in Table 15c represent:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for EDBs.*

Some generators that would pay direct connection charges but have relatively small injection quantities, including Pioneer, are omitted. This is because the metric of 'charge divided by generation injection' is not meaningful for such generators.

An updated version of the information provided in paras F.7 – F.9 of the options working paper follows. The data were originally embedded in the text, but are now provided in tabular form for readers' convenience.

Effect of options on prices faced by residential consumers, in c/kWh terms

Application A

	Base Option	Base Option + LRMC	Base Option + SPD
Alpine Energy	-0.40	-0.41	-0.41
Aurora Energy	-0.15	-0.17	-0.21
Buller Electricity	0.03	0.17	0.05
Counties Power	1.11	1.08	1.08
Eastland Network	0.29	0.26	0.28
Electra	0.65	0.62	0.64
Electricity Ashburton	0.14	0.20	0.13
Horizon	0.43	0.43	0.48
Mainpower	-0.26	-0.29	-0.32
Marlborough Lines	1.00	1.11	0.95
Network Tasman	0.01	0.02	-0.03
Network Waitaki	-0.36	-0.37	-0.40
Northpower	1.85	1.83	1.92
Orion	-0.77	-0.74	-0.81
Powerco	0.11	0.08	0.14
PowerNet	-0.38	-0.42	-0.40
Scanpower	-0.20	-0.23	-0.17
The Lines Company	0.28	0.27	0.26
Top Energy	2.35	2.33	2.30
Unison	-0.28	-0.31	-0.24
Vector	1.19	1.18	1.26
Waipa Power	-0.43	-0.46	-0.37
WEL	-0.19	-0.20	-0.15
Wellington Electricity	-0.64	-0.68	-0.57
Westpower	2.27	2.30	2.24

Application B

	Base Option	Base Option + LRMC	Base Option + SPD
Alpine Energy	-0.06	-0.07	-0.05
Aurora Energy	-0.06	-0.08	-0.05
Buller Electricity	-0.06	0.07	-0.05
Counties Power	0.23	0.22	0.23
Eastland Network	-0.08	-0.10	-0.07
Electra	-0.06	-0.08	-0.06
Electricity Ashburton	-0.03	0.04	-0.02
Horizon	0.05	0.06	0.05
Mainpower	-0.07	-0.10	-0.06
Marlborough Lines	-0.07	0.05	-0.06
Network Tasman	-0.06	-0.04	-0.04
Network Waitaki	-0.06	-0.06	-0.05
Northpower	-0.06	-0.08	-0.05
Orion	-0.09	-0.05	-0.07
Powerco	-0.07	-0.09	-0.07
PowerNet	0.09	0.05	0.10
Scanpower	-0.07	-0.10	-0.07
The Lines Company	-0.05	-0.05	-0.05
Top Energy	-0.05	-0.07	-0.06
Unison	-0.08	-0.10	-0.08
Vector	-0.05	-0.06	-0.04
Waipa Power	-0.07	-0.10	-0.07
WEL	-0.07	-0.08	-0.07
Wellington Electricity	-0.09	-0.13	-0.08
Westpower	-0.03	0.01	-0.02

Effect of options on prices faced by residential consumers, in % terms

Application A

	Base Option	Base Option + LRMC	Base Option + SPD
Alpine Energy	-1.6%	-1.7%	-1.7%
Aurora Energy	-0.6%	-0.7%	-0.9%
Buller Electricity	0.1%	0.7%	0.2%
Counties Power	4.6%	4.5%	4.5%
Eastland Network	1.2%	1.1%	1.2%
Electra	2.7%	2.6%	2.7%
Electricity Ashburton	0.6%	0.9%	0.5%
Horizon	1.8%	1.8%	2.0%
Mainpower	-1.1%	-1.2%	-1.3%
Marlborough Lines	4.2%	4.6%	4.0%
Network Tasman	0.1%	0.1%	-0.1%
Network Waitaki	-1.5%	-1.5%	-1.7%
Northpower	7.7%	7.6%	8.0%
Orion	-3.2%	-3.1%	-3.4%
Powerco	0.4%	0.3%	0.6%
PowerNet	-1.6%	-1.7%	-1.6%
Scanpower	-0.8%	-1.0%	-0.7%
The Lines Company	1.2%	1.1%	1.1%
Top Energy	9.8%	9.7%	9.6%
Unison	-1.2%	-1.3%	-1.0%
Vector	5.0%	4.9%	5.2%
Waipa Power	-1.8%	-1.9%	-1.5%
WEL	-0.8%	-0.8%	-0.6%
Wellington Electricity	-2.7%	-2.8%	-2.4%
Westpower	9.4%	9.6%	9.3%

Application B

	Base Option	Base Option + LRMC	Base Option + SPD
Alpine Energy	-0.2%	-0.3%	-0.2%
Aurora Energy	-0.3%	-0.3%	-0.2%
Buller Electricity	-0.2%	0.3%	-0.2%
Counties Power	1.0%	0.9%	1.0%
Eastland Network	-0.3%	-0.4%	-0.3%
Electra	-0.3%	-0.3%	-0.2%
Electricity Ashburton	-0.1%	0.2%	-0.1%
Horizon	0.2%	0.2%	0.2%
Mainpower	-0.3%	-0.4%	-0.3%
Marlborough Lines	-0.3%	0.2%	-0.2%
Network Tasman	-0.2%	-0.2%	-0.2%
Network Waitaki	-0.3%	-0.3%	-0.2%
Northpower	-0.2%	-0.3%	-0.2%
Orion	-0.4%	-0.2%	-0.3%
Powerco	-0.3%	-0.4%	-0.3%
PowerNet	0.4%	0.2%	0.4%
Scanpower	-0.3%	-0.4%	-0.3%
The Lines Company	-0.2%	-0.2%	-0.2%
Top Energy	-0.2%	-0.3%	-0.2%
Unison	-0.3%	-0.4%	-0.3%
Vector	-0.2%	-0.3%	-0.2%
Waipa Power	-0.3%	-0.4%	-0.3%
WEL	-0.3%	-0.3%	-0.3%
Wellington Electricity	-0.4%	-0.5%	-0.3%
Westpower	-0.1%	0.1%	-0.1%

The tables above are based on the assumptions that:

- all transmission charges on EDBs would be passed on from distributors to retailers, and retailers to customers, on a per-MWh basis
- all customer classes in a given EDB area would face the same transmission charge in per-MWh terms
- retail customers face a fully variabilised tariff of 24 c/kWh excl GST.

The tables do not include any caps or transitions. Nor do they take into account any reduction in transmission costs that might occur as a result of changing the TPM.

The modelling changes also impact on the main text of the TPM options working paper, in that:

- para 1.80 should be read as referring to a modelled 7.5% increase in electricity charges for retail customers in the Northpower area
- at para 6.103, ‘about $350 million per year’ should be read as ‘about $345 million per year’
- at para 11.31 (a), ‘$300M per year’ should be read as ‘$315 million per year’.

Table 15b, and the $/ICP section of Table 14, would also be affected by the corrections made, but have not been updated as they have been superseded by the publication of the ‘Modelled changes on residential load’ document (see Section 4 below).

Section 12 would also be affected by the corrections made, but has not been updated as it has been superseded by the publication of the ‘Caps and transitions’ document (see Section 5 below).

3. Deeper connection companion paper

The deeper connection companion paper was published at the same time as the options working paper, in order to provide submitters with more information about the detail of the deeper connection charge.

Revised versions of Tables 2a and 2c of the document are provided below.

Table 2a: Modelled incidence of deeper connection charges ($M per year)

Distributors		Generators		Major industrials	
Alpine Energy	0.79	Contact	29.54	CHH	0.54
Aurora Energy	0.49	Fonterra	0.07	Daiken MDF	0.08
Buller Electricity	0.73	Genesis	4.02	Kiwirail	0.00
Counties Power	4.49	Meridian	11.09	Methanex	0.09
Eastland Network	1.19	Mokai JV	0.11	Norske Skog	0.00
Electra	1.90	MRP	3.52	NZ Steel	0.03
Electricity Ashburton	0.00	NAP JV	1.07	NZAS	1.25
Horizon	0.05	Ngatamariki	0.55	Pacific Steel	0.72
Mainpower	0.81	NZ Wind Farms	0.00	PanPac	0.39
Marlborough Lines	5.19	Pioneer	0.49	Rayonier	0.31
Network Tasman	1.90	Todd	0.56	Winstones	0.00
Network Waitaki	0.00	Trustpower	2.00		
Northpower	25.14				
Orion	2.55				
Powerco	15.55				
PowerNet	3.01	(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)			
Scanpower	0.09				
The Lines Company	0.26				
Top Energy	7.05				
Unison	4.51	(incl. Centralines)			
Vector	170.28				
Waipa Power	0.05				
WEL	0.91				
Wellington Electricity	5.70				
Westpower	6.19				

Table 2c: Modelled incidence of deeper connection charges, on a fully variabilised basis ($/MWh)

Distributors		**Generators**		**Major industrials**	
Alpine Energy	1.03	Contact	2.70	CHH	0.85
Aurora Energy	0.35	Fonterra	0.49	Daiken MDF	1.13
Buller Electricity	6.29	Genesis	0.50	Kiwirail	0.10
Counties Power	9.23	Meridian	0.95	Methanex	2.03
Eastland Network	3.84	Mokai JV	0.12	Norske Skog	0.00
Electra	4.04	MRP	0.65	NZ Steel	0.03
Electricity Ashburton	0.00	NAP JV	0.91	NZAS	0.25
Horizon	0.10	Ngatamariki	0.86	Pacific Steel	3.54
Mainpower	1.54	Todd	0.00	PanPac	0.75
Marlborough Lines	13.08	Trustpower	0.25	Rayonier	5.39
Network Tasman	2.31			Winstones	0.00
Network Waitaki	0.00				
Northpower	23.89				
Orion	0.77				
Powerco	3.40				
PowerNet	2.00	(incl. The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)			
Scanpower	0.93				
The Lines Company	0.85				
Top Energy	20.01				
Unison	2.44	(incl. Centralines)			
Vector	19.02				
Waipa Power	0.12				
WEL	0.69				
Wellington Electricity	2.11				
Westpower	20.98				

Note: The figures in Table 2c represent:

- *for generators, charge divided by generation injection*
- *for major consumers, charge divided by load offtake*
- *for EDBs, charge divided by approximate gross electricity consumption.*

Some generators that would pay direct connection charges but have relatively small injection quantities, including Pioneer, are omitted. This is because the metric of 'charge divided by generation injection' is not meaningful for such generators.

The modelling changes also impact on the main text of the deeper connection companion paper, in that:

- at para 5.9, ‘approximately $300 million per year’ should now be read as ‘approximately $315 million per year’
- at para 5.10, ‘generation ($52 million per year) and load ($252 million per year)’ should now be read as ‘generation ($53 million per year) and load ($262 million per year)’.

Table 2b would also be affected by the corrections made, but has not been updated as it has been superseded by the publication of the ‘Modelled charges on residential load’ document (see Section 4 below).

Examples in paras 5.17-5.27 would also be affected by the corrections made (eg EDG-TRK would now be deeper connection for both load and generation), but have not been updated at this point, as they are examples only.

Similarly, Appendices B and C have not been updated at this point.

4. ‘Modelled charges on mass-market ‘residential load’ adopting a per-MWh pass-through basis’ document

The ‘Modelled charges on residential load’ document was published on the Authority’s website on 26 June 2015, in order to provide stakeholders with more information about the possible impact of the various options on residential customers.

Revised versions of Tables 1 and 2 of the document are provided below.

Table 1: Modelled charges on mass-market residential load, as $ per year for a typical household – modelled on the basis of pass-through according to consumption (MWh)

EDB area	Base Option	Base Option + LRMC	Base Option + SPD	Status quo
Alpine Energy	86	85	85	119
Aurora Energy	110	108	106	122
Buller Electricity	79	87	80	77
Counties Power	206	204	204	118
Eastland Network	133	131	133	115
Electra	142	140	141	100
Electricity Ashburton	74	80	73	62
Horizon	61	60	64	33
Mainpower	136	133	130	159
Marlborough Lines	192	200	189	120
Network Tasman	98	99	95	97
Network Waitaki	86	85	83	113
Northpower	218	216	223	100
Orion	111	115	109	179
Powerco	110	109	112	104
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	86	83	85	116
Scanpower	111	109	113	125
The Lines Company	129	128	127	106
Top Energy	225	223	222	82
Unison *(incl Centralines)*	110	108	112	130
Vector	227	226	231	142
Waipa Power	96	93	100	129

EDB area	Base Option	Base Option + LRMC	Base Option + SPD	Status quo
WEL	101	100	104	115
Wellington Electricity	111	108	116	157
Westpower	189	191	188	50

Table 2: Comparison between the figures in Table 1 above and those in Table 15b of the working paper, for the Base Option only

EDB area	Modelled charge, as $ per year for a typical household, from Table 1 above (on a passed through consumption (MWh) basis)	Modelled charge, as $ per ICP per year, from Table 15b of the working paper	Difference
Alpine Energy	86	263	177
Aurora Energy	110	220	110
Buller Electricity	79	372	293
Counties Power	206	339	133
Eastland Network	133	259	126
Electra	142	246	104
Electricity Ashburton	74	270	196
Horizon	61	214	153
Mainpower	136	228	92
Marlborough Lines	192	435	243
Network Tasman	98	252	154
Network Waitaki	86	229	143
Northpower	218	560	342
Orion	111	233	122
Powerco	110	258	148
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	86	257	171
Scanpower	111	220	109
The Lines Company	129	211	82
Top Energy	225	421	196
Unison *(incl Centralines)*	110	250	140
Vector	227	519	292
Waipa Power	96	203	107

EDB area	Modelled charge, as $ per year for a typical household, from Table 1 above (on a passed through consumption (MWh) basis)	Modelled charge, as $ per ICP per year, from Table 15b of the working paper	Difference
WEL	101	222	121
Wellington Electricity	111	258	147
Westpower	189	676	487

These changes impact on the main text of the modelled charges on residential load document, in that the following sentence on page 1 of the document:

> Westpower residential customers are modelled to pay $187 per year in Table 1 as opposed to $676 in Table 15b of the options working paper; and Top Energy $223 as opposed to $421.

should now be read as follows:

> Westpower residential customers are modelled to pay $189 per year in Table 1 as opposed to $676 in Table 15b of the options working paper; and Top Energy $225 as opposed to $421.

(These figures are shown in red in Table 2 above.)

5. ‘Modelling of caps and transitions for the TPM options working paper ’ document

The ‘Caps and transitions’ document was published on the Authority’s website on 26 June 2015 in order to provide stakeholders with more information about how the impacts of Application A on some parties could be mitigated.

Revised versions of Tables 1 and 2 of the document are provided below.

Table 1: Modelled charges on mass-market load, as $ per year for a typical household, under the Base Option of Application A

EDB area	Status quo	Alternative 1: a cap	Alternative 2: a transition	Alternative 3: a transition	Alternative 4: a transition	No transition or cap
Alpine Energy	119	149	87	100	103	86
Aurora Energy	122	156	112	115	115	110
Buller Electricity	77	106	80	79	77	79
Counties Power	118	(*) 200	207	188	165	206
Eastland Network	115	137	134	133	120	133
Electra	100	142	143	135	115	142
Electricity Ashburton	62	151	75	74	66	74
Horizon	33	112	62	49	44	61
Mainpower	159	175	137	146	147	136
Marlborough Lines	120	159	194	170	147	193
Network Tasman	97	134	99	98	96	98
Network Waitaki	113	138	87	97	100	86
Northpower	100	141	206	147	145	218
Orion	179	165	113	140	148	111
Powerco	104	130	111	110	104	110
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	116	152	87	99	109	86
Scanpower	125	141	112	117	117	111
The Lines Company	106	160	130	128	113	129
Top Energy	82	134	204	120	138	225

Unison *(incl Centralines)*	130	140	111	118	119	110
Vector	142	159	228	203	175	227
Waipa Power	129	143	97	110	113	96
WEL	115	136	102	107	107	101
Wellington Electricity	157	141	112	130	135	111
Westpower	50	135	169	73	105	189

(*) The relatively high rate paid by households in the Counties Power area under Alternative 1 arises because Counties Power is modelled as paying the costs of a hypothetical new investment reinforcing Otahuhu - Wiri. Because the Otahuhu - Wiri upgrade is modelled as taking place after the new Guidelines are published, charges with respect to this investment are not subject to the cap.

Table 2: Charging rates under the Base Option of Application A ($/MWh)

	Status quo	Alternative 1: a cap	Alternative 2: a transition	Alternative 3: a transition	Alternative 4: a transition	No transition or cap
Generators						
Contact	2.5	3.9	3.9	3.9	3.7	3.9
Genesis	0.9	1.0	1.0	1.0	1.0	1.0
Meridian	7.9	3.7	3.7	3.7	6.3	3.7
Mokai JV	0.0	0.6	0.6	0.6	0.3	0.6
MRP	0.0	0.9	0.9	0.9	0.5	0.9
NAP JV	0.0	1.4	1.4	1.4	0.7	1.4
Ngatamariki	0.0	1.3	1.3	1.3	0.6	1.3
Todd	0.0	1.2	1.2	1.2	0.6	1.2
Trustpower	1.4	2.5	2.5	2.5	1.9	2.5
Major industrials						
CHH	7.0	2.2	2.2	4.2	4.9	2.2
Daiken MDF	12.1	2.6	2.6	6.6	8.0	2.6
Kiwirail	12.0	4.1	4.1	7.5	8.6	4.1
Methanex	12.0	4.0	4.0	7.3	8.5	4.0
Norske Skog	0.0	2.1	2.1	0.0	0.9	2.1
NZ Steel	8.6	1.6	1.6	4.6	5.7	1.6
NZAS	12.4	1.3	1.3	6.0	7.7	1.3
Pacific Steel	17.9	6.1	6.1	11.1	13.2	6.1

	Status quo	Alternative 1: a cap	Alternative 2: a transition	Alternative 3: a transition	Alternative 4: a transition	No transition or cap
PanPac	4.2	2.3	2.3	3.1	3.4	2.3
Rayonier	12.7	6.9	6.9	9.4	(*) 13.1	6.9
Winstones	13.0	1.4	1.4	6.3	8.1	1.4

(*) The relatively high value for Rayonier under Alternative 4 stems from the relatively high contribution (in $/MWh terms) that Rayonier is assumed to make to recovering the costs of the LSI Reliability upgrade, under the deeper connection method. Because the LSI Reliability upgrade is modelled as being completed after the new Guidelines are published, charges with respect to this investment are not transitioned.

These changes impact on the main text of the caps and transitions document, in that:

- the cost of Alternative 1 (a cap) is now modelled as about $108 million per year (was $95 million) (page 1)
- the cost of Alternative 2 (a transition) is now modelled as about $5 million per year (was $3 million) (page 2)
- the cost of Alternative 3 (a transition) is now modelled as about $59 million per year (was $50 million) (page 2).