MEMO

To Alan Eyes

From Mike Hensen

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Subject TPM 2019 Anytime Maximum Demand Analysis

Purpose

This note compares three approaches to using anytime maximum demand (AMD) to allocate 'residual' transmission costs between electricity distribution business (EDB) and direct connect consumers:

- The Electricity Authority (EA) in transmission pricing methodology (TPM) 2019 proposed using historical AMD for EDB and direct connect consumers. This approach allocates about 12 percent of the residual to direct connect consumers.
- TPM June 2015 allocation based on deemed capacity for EDB consumers and share of AMD for direct connect consumers. This approach would allocate about 2 percent of the TPM 2019 residual to direct connect consumers
- Multiplying EDB total AMD by a high factor (2.5) or a low factor (1.5) to adjust for the 'diversity' effect on EDB AMD. A low (high) factor would reduce the reduce the direct connect consumer share of the residual from about 12 percent to about 8.4 percent (5.2 percent).

The note also includes a brief comment on the:

- Range of EDB approaches to using AMD to recover their EDB electricity delivery costs (which are about double Transpower's costs) from customers.
- The appropriateness or otherwise of each of the three approaches for the residual.

Applying TPM 2015 to TPM 2019 data

In TPM 2015 the EA argued that the capacity of connections to the grid determines the maximum potential demand for transmission services from the consumers using those connections and suggested that this could be measured for EDB by the nominal capacity of consumer connections and for direct connect consumers by their AMD.

The key differences between the TPM 2015 and TPM 2019 allocation of the residual costs are:

- TPM 2019 allocated 1.9 percent of the residual to New Zealand Steel compared with:
  - 0.3 percent if the TPM 2015 residual allocation method was applied to 2019 data
  - 0.5 percent in TPM 2015 (0.4 percent for New Zealand Steel and 0.1 percent for Pacific Steel)
- TPM 2019 residual is approximately $494 million, about 43 percent higher than the TPM 2015 residual of approximately $344 million.

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The effects of the differences between the TPM 2015 and TPM 2019 methods is analysed in detail in Appendix A.

High and low estimates of EDB AMD

Total EDB AMD is lower than the sum of AMD for separate EDB customer groups because maximum demand occurs at different times for different EDB customer groups. However quantitative evidence of the difference between EDB AMD and the sum of AMD for individual customer groups is only available for some EDB. Appendix B describes the analysis of EDB AMD and indicates that the sum of AMD for separate EDB customer groups could be 1.5 to 2.5 times the total AMD for an EDB – see B.2 and Table 7.

EDB approach to recovery of charges from consumers

EDB group their consumers based on the capacity of their connection and the extent to which they use the high and low voltage networks. After defining customer groups, EDB use a combination of indicators to allocate costs across their consumer groups including RCPD, AMD by customer group and number of connections. [1]

EDB use a combination of allocators to reflect the different drivers of distribution asset costs:

- some assets are shared by users and sized to meet peak demand – consumer share of coincident peak demand is the appropriate allocator to recover these costs
- some assets are sized for individual connections (low voltage assets), or tend to have a fixed size regardless of loading levels – share of the sum of consumer AMD is the appropriate allocator to recover these costs

Appropriate allocator

The TPM 2019 discussion of allocators of common or 'residual' charges includes two changes:

- Using share of AMD instead of RCPD as the allocator
- Setting the allocator using historical averages and leaving it unchanged for five to 10 years instead of annual reset.

RCPD is likely to be a better measure of the contribution of consumers to peak demand that justify an increase in grid capacity than consumer AMD because it is an average of periods when the grid is most heavily used.

Setting the allocator on recent history and only amending it after a long lag is inconsistent with the annual reset approach to the allocation of EDB costs and removes an incentive for users to flatten their load profile.

[1] EDB allocate pass-through transmission charges using the same method as Transpower use to allocate the charges to EDB – share of RCPD for interconnection charges and AMD for connection charges

Appendix A EA TPM 16 June 2015[2]

A.1 Introduction

This section summarises the key comments from the TPM 2016 working paper on the use of deemed capacity for EDB customers and AMD for direct connect customers to allocate residual transmission charges:

6.95 The Authority proposes that the residual charge be calculated according to the connection capacity of loads.

6.96 The Authority considers that a residual charge calculated according to connection capacity may limit distortions in use of the grid because it would be relatively difficult to alter.

6.97 Further, in general, a party's maximum potential demand for transmission services is determined by the capacity of its connection to the grid, whether directly or indirectly. Charging on a capacity basis would spread the cost across all load parties that use the grid rather than concentrating it just on those using the grid during peaks, as under the current RCPD charges. This should broaden the base upon which the charge is levied, which would lower its rate, and reduce distortions from the charge.[3]

6.102 The Authority has not yet developed a pure capacity-based charge on load. Therefore, for the purpose of this working paper, the Authority has modelled the capacity-based charge as being allocated in proportion to:

(a) deemed capacity, for EDBs – calculated as the sum of the nominal capacities of the active ICPs in their network area. The nominal capacity depends on the ICP's metering category code, ranging from 20 kW for category code 1 to 2500 kW for category code 5.[104]

(b) AMD, for major industrial customers. The reason for this is that the capacity of some direct connect customers' connections substantially exceeds their demand for transmission services, so a reasonable proxy for their connection capacity requirements is AMD. If allocating the residual charge to industrial consumers on an AMD basis resulted in activity to embed their demand (that is, obtain electricity supply through the local distribution network), this would need to be addressed through the prudent discount policy.

6.103 The outcome of modelling is illustrated in Figure 4, with the capacity charge (residual charge) on load recovering about $350 million per year.

2 'Transmission Pricing Methodology Review: TPM options, Working paper, 16 June 2015' available at https://electricityauthority.cwp.govt.nz/dmsdocument/19472-transmission-pricing-methodology-review-tpm-options

3 Op cit page 51

A.2 Source for meter numbers by category[4]

> *175 Each metered ICP is assigned a meter category code, indicating the capacity of the customer connection. These codes are explained at: http://www.ea.govt.nz/dmsdocument/8583. For instance, a 400V non-half-hourly meter with maximum current of 200 kVA would be code 2. Numbers of ICPs by meter category code are published at: http://www.emi.ea.govt.nz/Reports/VisualChart?reportName=AWNGPD&categoryName=Retail&reportGroupIndex=9&reportDisplayContext=Gallery#reportName=AWNGPD.*

A.3 Updating TPM 2015 residual allocator with TPM 2019 data

The TPM 2015 papers include an estimate of the:

- deemed capacity of each EDB based on the number of meters in each of six types multiplied by the nominal capacity (measured in kW) of meters in that type[5]
- a percentage allocation of the residual charge for each EDB and direct connect consumers[6].

According to the text quoted in A.1 the allocation of the residual charge was based on total deemed capacity for EDB plus actual AMD for direct connect consumers. I have not been able to find a list of AMD data for the direct connect consumers in TPM 2015.

However, allocation of the $344 million residual allocation in TPM 2015 shows:

- 97.39 percent ($335 million) of the residual charge allocated to EDB based on a total capacity of 47,031 MW
- 2.61 percent ($9 million) of the residual charge allocated to direct connect consumers implying a total AMD of 1,262 MW.

The implied AMD for the direct connect consumers in 2015 is shown in the following table. and compared with the Gross AMD data used in TPM 2019[7]. The total level of 2014-15 Gross AMD for direct connect consumers reported in TPM 2019 is 157.4 MW lower than the estimated AMD for 2014 reported in TPM 2015 mainly due to five direct connect consumers that were listed in TPM 2015 not being listed in TPM 2019. In particular direct connect consumer:

- AMD totalling 166.6 MW for Carter Holt Harvey (87.2 MW), Daiken MDF (11.9 MW), Fonterra (9.9 MW) and Pacific Steel (57.7 MW) was included in TPM 2015 but omitted from TPM 2019

4 Op cit page 109. The metre types and their nominal capacities are unmetered (20 kW), 1 (20 kW), 2 (100 kW), 3 (700 kW), 4 (1,750 kW) and 5 (2,500 kW)

5 See "EA dataset files\Preprocessing\ICP_charge_calculations_-_by_customer.xlsx, ICP charge calculations, B2:J30"

6 See: "EA dataset files\Combinations\Caps_and_transitions\Workings_for_caps_and_transitions_updated_31July2015.xlsx, Working, H3:H49"

7 The matching of direct connect industrials from TPM 2015 to TPM 2019 was checked matching the four letter code for the network participant in the TPM 2019 Gross AMD Calculation the more detailed network participant name in the EA network supply points table available at https://www.emi.ea.govt.nz/Wholesale/Reports/R_NSPL_DR?_si=v|5

- AMD totalling 9.3 MW for B.E.R. (Kupe) Ltd (8.9 MW), Port Taranaki (0.2 MW) and Southpark Utilities (0.1 MW) was omitted from TPM 2015 but included in TPM 2019.

Table 1 AMD for TPM 2015 and TPM 2019

Estimated AMD for 2015 and reported AMD for 2019 in MW

TPM 2015 direct connect	TPM 2019 direct connect	AMD 2014 (estimate) (TPM 2015)	Gross AMD 2014 - 2015 (TPM 2019)	Gross AMD 2017 - 2018 (TPM 2019)
	B.E.R. (Kupe) Ltd		8.9	9.5
Rayonier	Daiken Southland	9.6	8.8	9.3
Methanex	Methanex	9.9	9.1	9.1
Kiwirail	New Zealand Rail	17.7	40.0	44.6
Norske Skog	Norske Skog	121.0	114.5	103.2
NZ Steel	NZ Steel	171.5	171.6	170.0
Pacific Aluminium	NZAS	634.6	583.5	583.5
PanPac	Pan Pacific	87.5	81.1	77.5
	Port Taranaki		0.2	0.3
	Resolution Dev			
	Southpark Utilities		0.1	0.2
Winstones	Winstone Pulp Int	43.6	37.1	36.3
CHH		87.2		
Daiken MDF		11.9		
Fonterra		9.9		
Pacific Steel		57.7		
Total		**1,262.1**	**1,054.9**	**1,043.4**

Source: NZIER

After adjusting for the difference in coverage, the estimated TPM 2015 AMD the Gross AMD for 2014-2015 reported in TPM 2019 differ by only 49.8 MW or about 4 percent.

The Gross AMD reported in TPM 2019 for the four years 2014-15 to 2017-18 has been stable with a simple average of 1,049.3 MW and a range of 1043.4 MW (0.6 percent below the average) to 1,054.9 MW (0.5 percent above the average).

In contrast the deemed capacity for EDB has increased by about 3,740 MW (8.0 percent) between TPM 2014 and November 2019 (after deducting the 157.4 MW to allow for the change in definition of direct connect consumer between TPM 2014 and TPM 2019). Admittedly this comparison period for the change in EDB deemed capacity is more than a year longer than the comparison period for change in Gross AMD. However, I could not find EDB connection data by meter type for 2018. As the increase in EDB deemed capacity is driven by steady growth in the number of connections, 5.8 percent is a reasonable estimate of the increase in deemed capacity over the period covered by the TPM 2019 Gross AMD data.

Table 2 Deemed EDB capacity

Actual for TPM2015 and estimated for November 2019 in MW

EDB name (2019)	TPM2015	Nov 2019
Alpine Energy	803.3	860.4
Aurora Energy	2,062.0	2,191.1
Buller Electricity	107.7	105.4
Centralines		184.2
Counties Power	882.4	1,022.8
Eastland Network	583.6	602.2
Electra	944.7	993.8
Electricity Ashburton	546.7	607.3
Electricity Invercargill		407.2
Horizon Energy	550.8	576.8
MainPower	824.2	943.6
Marlborough Lines	609.5	643.4
Nelson Electricity		227.8
Network Tasman	1,095.2	962.1
Network Waitaki	317.9	347.1
Northpower	1,192.1	1,291.2
Orion	4,483.3	5,096.4
OtagoNet JV		353.5
Powerco	7,053.2	7,556.7
Powernet	1481.9	
Scanpower	148.6	150.2
The Lines Company	515.3	546.6
The Power Company		843.4
Top Energy	660.2	713.7
Unison Networks	2,647.0	2,606.7
Vector	12,635.3	13,789.4
Waipa Networks	540.4	601.3
WEL Networks	1,997.3	2,184.8
Wellington Electricity	4,022.3	4,186.0
Westpower	326.5	333.1
Total	**47,031.4**	**50,928.0**

Source: NZIER

A.4 TPM 2019 share of residual based on TPM 2015 approach

Table 3 shows the estimated residual allocator for TPM 2019 based on applying the TPM 2015 method of deemed capacity for EDB plus AMD for direct connect consumers to 2019 data and compares this to the allocation of the residual to the allocation proposed by the EA in TPM 2019.

Table 3 Residual allocation for TPM 2019 using TPM 2015 approach

Share of residual allocated to EDB, generators and direct connect consumers

TPM 2015 customer	TPM 2019 customer	TPM 2015	TPM 2019 based on TPM 2015	TPM 2019 proposed by EA	EDB AMD multiplied by 1.5	EDB AMD multiplied by 2.5
EDB	EDB	97.4%	98.0%	86.3%	90.5%	94.1%
	Generators			1.7%	1.1%	0.7%
Direct connect	Direct connect	2.61%	2.0%	12.0%	8.4%	5.2%

Source: NZIER

The TPM 2019 methodology increases the allocation of the residual to direct connect consumers by 10 percentage (a factor of 6) and spreads this share over a smaller group of customers as shown in Table 4.

Table 4 Residual allocation for TPM 2019 using TPM 2015 approach

Share of residual allocated to direct connect consumers

TPM 2015 customer	TPM 2019 customer	TPM 2015	TPM 2019 based on TPM 2015	TPM 2019 proposed by EA	EDB AMD multiplied by 1.5	EDB AMD multiplied by 2.5
Rayonier	Daiken Southland	0.0%	0.0%	0.1%	0.1%	0.0%
Methanex	Methanex	0.0%	0.0%	0.1%	0.1%	0.0%
Kiwirail	New Zealand Rail	0.0%	0.1%	0.5%	0.3%	0.2%
Norske Skog	Norske Skog	0.3%	0.2%	1.3%	0.9%	0.6%
NZ Steel	NZ Steel	0.4%	0.3%	1.9%	1.4%	0.8%
Pacific Aluminium	NZAS	1.3%	1.1%	6.7%	4.7%	2.9%
PanPac	Pan Pacific	0.2%	0.1%	0.9%	0.6%	0.4%
Winstones	Winstone Pulp Int	0.1%	0.1%	0.4%	0.3%	0.2%
Total common	**Total common**	**2.3%**	**2.0%**	**11.9%**	**8.3%**	**5.2%**
	B.E.R. (Kupe) Ltd		0.0%	0.1%	0.1%	0.0%
	Port Taranaki		0.0%	0.0%	0.0%	0.0%
	Resolution Dev		0.0%	0.0%	0.0%	0.0%
	Southpark Utilities		0.0%	0.0%	0.0%	0.0%
	Total TPM 2019 only		**0.0%**	**0.1%**	**0.1%**	**0.0%**
CHH		0.2%				
Daiken MDF		0.0%				
Fonterra		0.0%				
Pacific Steel		0.1%				
Total TPM 2015 only		**0.3%**				

Source: NZIER

A.5 Difference in between TPM 2015 and TPM 2019 residual

The TPM 2015 residual was approximately $344 million while the proposed TPM 2019 residual is approximately $494 million (about 43 percent higher).

Table 5 reports the proposed residual charges for direct connect consumers listed in both from TPM2015 and TPM2019 along with the estimated TPM 2019 residual charge if EDB AMD was multiplied by a factor of 1.5 or 2.5.

Table 5 Residual charges for TPM 2019 using TPM 2015 approach

Residual in $m

TPM 2019 customer	TPM 2015	TPM 2019 based on TPM 2015	TPM 2019 proposed by EA	EDB AMD multiplied by 1.5	EDB AMD multiplied by 2.5
Daiken Southland	0.1	0.1	0.5	0.3	0.2
Methanex	0.1	0.1	0.5	0.3	0.2
New Zealand Rail	0.1	0.1	2.4	1.7	1.0
Norske Skog	0.9	0.4	6.4	4.5	2.8
NZ Steel	1.2	1.0	9.6	6.7	4.2
NZAS	4.5	1.6	32.9	23.0	14.3
Pan Pacific	0.6	5.5	4.4	3.1	1.9
Winstone Pulp Int	0.3	0.7	2.1	1.5	0.9
Total	**7.8**	**9.6**	**58.8**	**41.1**	**25.6**

Source: NZIER

Appendix B AMD of EDB customer groups

B.1 Introduction

The EA TPM proposal acknowledges that the AMD allocator does not allow for after diversity demand at paragraph B.202 of TPM 2019[8] and suggests the Transpower could consider how to adjust the allocator for large loads connected to EDB at B.206[9] page 153. However, the EA has not done any modelling of the effect on allowing for AMD of individual EDB connections.

> *B.202 By contrast, an allocator based on annual electricity consumption has the advantage that it treats grid-connected and embedded load customers in the same manner (which would reduce distortion to location and connection decisions). This would address the legitimate concerns of those submitters who considered that AMD disadvantages grid connected grid users relative to those who connect behind, and can therefore benefit from, the averaging implicit in a distributors' AMD. On the other hand, it may have a relatively greater impact on price-sensitive customers (and so distort such customers' decision-making). Large industrial consumers, for example, tend to have a demand profile with less pronounced peaks compared to households, so an allocator based on annual consumption would have a relatively greater effect on an industrial than an AMD allocator. ...*
>
> *B.206 The proposals discussed under the heading General matters above and the heading Provisions relating to adjustments mean that Transpower would need to consider the various potential inefficiencies discussed above in the detailed design of the charge. For example, it could calculate the part of a distributor's residual charge attributable to large load connected to it as if the large load was grid-connected at the distributor's point of connection.*

The EA's cursory consideration of AMD for individual large EDB load seems to be inconsistent with its approach to AMD for customers with multiple connection points where the EA favours a non-coincident peak measure of the AMD for these customers effectively denying these customers the benefit of diversity within their load paragraphs B.207 to B.209[10] on page 153

> *B.209 Our view is that the residual charge should be allocated in proportion to a customers' size (and so reflective of their likely willingness and ability to pay). As is discussed in appendix D: decision making framework, allocation of common costs in this way is consistent with what would occur in a workably competitive market. Our current view is that a 'non-coincident peak' measure of AMD is a better proxy for the size of the customer base in a location and its ability to pay charges, however, we are open to considering arguments for the alternative approach.*

[8] '2019 issues paper, Transmission pricing review, Consultation paper, 23 July 2019' EA page 152.

[9] '2019 issues paper, Transmission pricing review, Consultation paper, 23 July 2019' EA page 153.

[10] '2019 issues paper, Transmission pricing review, Consultation paper, 23 July 2019' EA page 153.

B.2 EDB pricing methodology data

Some EDB include data on both the AMD and an equivalent to RCPD for customer groups. Table 6 below compares the AMD and coincident peak demand measures for Powerco, Orion, Unison and Aurora by customer group.

Table 6 EDB AMD as a multiple of coincident peak demand

Comparison by customer group

EDB	Group	AMD (MW)	Coincident Peak (MW)	AMD/ Coincident Peak
Large				
Powerco	>300 kVa	273	121	2.27
Orion	Large capacity	32	27	1.18
Unison	Large	73	33	2.21
Aurora	>500 kVa	60	34	1.74
Electricity Ashburton		18		
Medium				
Powerco	100 to 300 kVa	265	34	7.79
Orion	Major connections	224	110	2.04
Unison	Medium	343	78	4.39
Aurora	150-499 kVa	34	23	1.50
Electricity Ashburton	Industrial and irrigation	151		
Residential				
Powerco				
Orion	General connections	1,967	469	4.19
Unison	Small	642	176	3.64
Aurora	0 -150 kVa	283	218	1.30
Electricity Ashburton		92		

Source: NZIER

Of the ten largest[11] EDB, four (Powerco, Orion, Unison and Aurora) report data on AMD and an RCPD equivalent for non-residential customer groups and three (Orion, Unison and Aurora) report the same data for residential customers as well.

11 The ten largest EDB ranked by energy delivered in descending order are: Vector, Powerco, Orion, Wellington Electricity, Unison, Aurora, WEL Networks, Electricity Ashburton, Northpower and Alpine Energy. Vector and Wellington Electricity do not report AMD for their customers. Vector does use maximum demand for large non-residential customers as part of its pricing methodology, but Wellington Electricity only uses coincident peak demand rather than both AMD and coincident peak demand. The analysis covered the ten largest EDB as they account for 80 percent of the total AMD for EDB.

Comparison of the data indicates that for:

- Medium sized non-residential connections AMD is at least twice coincident peak demand
- Residential and small business connections AMD can be three to four times coincident peak demand

Table 7 compares the EA estimate of AMD with the EDB sum of AMD reported for individual connections. For Orion and Unison, the EDB sum of AMD for individual customer groups is more than 2.5 times the EA estimate of AMD while for Electricity Ashburton the EDB sum of AMD for individual customer groups is more than 1.4 times the EA estimate of AMD. (It is not clear from the definition of the Aurora statistics that AMD for each group is being measured at the peak demand time for each group rather than the network.)

Table 7 Comparison of EA and EDB estimates of AMD

Demand measures reported in MW

EDB	EDB Coincident Peak Demand[1]		EA AMD Estimate	EDB Sum of AMD for Individual Connection groups	
	2018	2019	2018	2018	2019
Vector	1,671	1658	2,046		
Powerco			1,046		
Orion	665	666	825	2,382	2,327
Wellington Electricity			584		
Unison	284	287	407	1,060	1,057
Aurora	214	276	359	300	379
WEL Networks			306		
Electricity Ashburton[3]			194		260
Northpower			180		
Alpine Energy			167		

Notes:

1. From EDB pricing methodology disclosures for 2018 and 2019
2. Calculated from EA worksheet 'Gross AMD Calculation'
3. Measured demand from pricing methodology

Source: NZIER