TPM second issues paper

Advice to MEUG on TPM cost benefit analysis

NZIER report to MEUG

20 July 2016

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1. Overview

1.1. Purpose

The Electricity Authority (EA) is seeking submitter views on the Transmission Pricing Methodology: Issues and proposal;[1] Second Issues paper (TPM2). The paper is a set of guidelines for the development of a new transmission pricing methodology to be developed by Transpower.

The purpose of this report is

(1) to respond to the questions asked by MEUG in the ToR about testing the TPM2 cost benefit analysis and

(2) to comment on the proposals for the extension of the Prudent Discount Policy (PDP) and the changes to the distributed generation policy.

This report is organised into sections that address each of these questions. The report also compares TPM2 to the previous transmission pricing methodology proposal described in 'Transmission Pricing Methodology Review: TPM options Working paper 16 June 2015' referred to in this report as TPM1[2].

As the ToR stresses a preference for quantitative analysis the answers to these questions are based on publicly available current or recent historical data and electricity demand forecasts. The main sources of data used for this analysis are:

- EA spreadsheets released with TPM2 and TPM1
- EA wholesale market datasets for 2014
- Information disclosures made by lines companies to the Commerce Commission
- electricity demand and generation scenarios (EDGS) forecasts released by MBIE[3] and Transpower forecasts of peak demand[4] both released in 2015.

The paper also includes brief comments on key issues with the current version of the TPM including the following:

- differences between the TPM approach between the first and second TPM proposals despite the application of the same set of principles and essentially the same data
- potential range of variation in the development of a transmission pricing methodology by Transpower based on the EA guidelines.

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1 The full title for the paper is 'Transmission Pricing Methodology: Issues and proposal; Second Issues paper, 17 May 2016' by the Electricity Authority.

2 This definition of TPM1 also includes supporting Appendixes, spreadsheets and revisions to documents and forecasts released by the EA as part of the consultation on TPM1.

3 At the time of writing we understand that MBIE is preparing a final version of the EDGS forecasts but these are unlikely to be released until late July or August.

4 'Electricity Peak Demand Forecasts Overview Of Our Peak Demand Forecast Methodology' Transpower New Zealand Limited February 2015.

1.2. EA problem definition

The EA has defined the problem as finding pricing mechanisms to allocate the maximum allowable revenue (MAR) set by the Commerce Commission so that:

- efficient use of the grid is maximised, in other words:
  - consumers pay for the benefit of using the grid where this can be identified
  - fees to recovery the residual charge are difficult for consumers to lower or avoid
- consumers have stronger incentives to scrutinise and submit arguments to the Commerce Commission/Transpower on Transpower investments as they will be charged for the cost or anticipated benefit of the asset.

2. Testing the CBA

2.1. Introduction

This section covers paragraphs 6a) and 6b) of the ToR 'Testing the CBA' and covers the following issues:

- are the policy problems well defined (four sub-questions)
- have other feasible options been considered (two sub-questions)
- has the best feasible option been proposed (two sub- questions)

Each of the sections address a single high level or sub-question and begins with a quotation of the ToR question that is being answered in that section.

2.2. Policy problem definition

2.2.1. Policy problem definition

> *a) Are the policy problems well defined? An important aspect is to define the counterfactual stated by the EA as being the status quo. Other questions include:*

The policy problem that the EA is trying to address is well-defined in a narrow sense. The policy problem definition focuses on maximising efficient use of the current transmission grid to recover Transpower maximum allowable revenue (MAR) and providing signals for future investment in a situation where in general the grid has excess capacity. The EA propose to achieve this by redesigning the costs allocation by adopting:

- cost allocation that encourages under use of the existing grid, specifically:
  - replacement of the regional coincident peak demand (RCPD) allocator with historical any time maximum demand (AMD) to prevent consumers from changing their demand patterns to avoid or reduce interconnection charges. (The key change is the use of a historical allocator which makes the charge unavoidable unless there is full disconnection, rather than the switch from AMD to RCPD.)
  - introducing an area of benefit (AoB) charge to allow recovery of the costs of assets from beneficiaries where a sub-group of beneficiaries can be identified
- allocation of the costs of planned investments in advance through estimation and publication of the AoB charge that would apply to the assets and setting of the AoB charge in advance to encourage efficient grid investment and use decision making. (The key assumption here is that subgroups of beneficiaries can be identified before investment decisions

are made and that the consumption patterns for this group will remain reasonably stable after the investment is made.)[5]

The core policy problem is defined qualitatively as the allocation of transmission costs so that the electricity grid is used efficiently and customers have strong incentives to ensure future investment decisions are efficient (in the sense that the existing customers that are likely to be charged for the investment will be informed of the cost of the investment).

Quantitative problem definition

The EA cannot quantify the difference between the allocation of a given transmission pricing mechanism and the ideal that would be generated by a perfectly competitive market. However the EA can identify different allocation regimes based on economic principles and then compare the expected difference in the effect of the reallocation costs on the use of the grid and electricity as well the cost of the implementing the new mechanism.

For this approach to deliver a solution in which the expected benefits exceed the costs (including the cost of implementation) the following conditions must be satisfied:

- it needs to be possible to translate the economic principles into price signals that will be sent, received and responded to as expected
- changes in the use of the grid in response to changes in cost allocation need to reflect the decisions taken by consumers about electricity use not just use of the grid
- the new investment signals created by the reallocation of costs of future transmission asset need to be received and acted on by consumers and the consumers.
- a mechanism for the cost allocation to evolve over time in response to change in grid use that does not create incentives for investment in activity that leads to 'inefficient' under use of the grid.

Therefore the quantitative definition of the problem that the EA is trying to solve is the net present value of difference between the current 'situation' and the 'situation' expected under the new cost allocation where the different 'situations' are defined by the set of selected effects expected from the change in cost allocation. This approach carries a risk of generating a circular argument if the potential consumer responses to reallocation of charges cannot be modelled reliably.

In practical terms the extreme difficulty of identifying sub-groups of direct beneficiaries of network assets[6] has affected the EA's TPM proposal in the following ways:

- most of the Transpower charges have to be treated as residual that cannot be allocated to any group of users because the modelling methods available

[5] The EA guidelines allow for optimisation of assets after construction but this is unlikely to be an attractive option for Transpower and it does not appear that Transpower is compelled to invoke the optimisation process if asset utilisation falls below expected levels.

[6] A large part of these difficulties arises the nature of network assets which typically have expected asset lives that are much longer than the planning horizons of the users of those assets, where there are significant long tem economies from building the network with greater capacity than required for current demand and where as long as the network has spare capacity the addition of new users lowers the cost to all uses but as soon as the asset becomes congested existing users face a step change in costs to accommodate a small number of new users.

(flow tracing and the deeper connection charge are regarded as too complex to implement and cannot produce an allocation of costs that is sufficiently granular to justify the effort)

- the AoB charges are based on a modelling of the benefits of large investments on the assumption that the particular asset was removed from the network (apparently vSPD modelling) but this approach is only workable for large assets with a major effect on the network.

For the AoB charge to become a larger part of the recovery of Transpower MAR, Transpower would have to be able to identify sub-groups of beneficiaries[7] for new and existing assets with more granularity than it has been capable of in the past or than the EA has been capable of In previous modelling attempts. It is not clear from the EA guidelines how this could be achieved or the extent to which this would be necessary to achieve EA objectives.

Same principles different answer

TPM2 applied the same set of cost allocation principles as TPM1, and TPM2 is compared by the EA to TPM1 as

> *a simpler proposal consisting of fewer charging elements that incorporate a number of pragmatic judgements*[8]

However the application of the same set of 'decision-making and economic framework' in TPM1 and TPM2 principles has led to a markedly different allocation of costs between EDBs and direct connect industrials. The difference is mainly due to the EA proposal to allocate the residual charge and approximately $47 million of the AoB[9] charge using the same historical measure of capacity for EDBs and industrials rather than the hybrid of AMD for industrials and deemed capacity for EDBs proposed in TPM1.

The estimated difference in the cost allocation shares for the residual charge between TPM1 and TPM2 is shown in Table 1 for electricity distribution businesses (EDBs) and Table 2 for industrials. The estimates for TPM2 in the following tables are taken from the EA 'Results_20160517b' spreadsheet but this spreadsheet includes a small allocation (about 2 percent) of residual cost to nodes owned by generators which does not seem to be consistent with the allocation of residual cost described in the TPM2

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7 The TPM paper identifies examples such as the cost of providing a transmission services to Westland and the potential request for undergrounding of transmission links in Auckland as reasons why an AoB charge is needed. It would help to gauge the materiality of this issue if the EA or Transpower could provide an indication of how the cost recovery of the Major Capex (average of $102 m per year for RCP2 and RCP3) and Base Capex (average of $200m per year RCP2 and RCP3) listed in the Transpower Integrated Transmission Plan would change under the TPM2 AoB charge compared with the status quo.

8 Transmission pricing methodology: issues and proposal Second issues paper.17 May 2016, Electricity Authority paragraph 5, p ii.

9 TPM2 proposes that about $40m of the $290m AoB charge to SI generators with rest of the AoB charge allocated to load customers in various areas. The replacement of the HVDC charge with the AoB charge reduces the transmission charges to SI generators by about $110m. The AoB charge for assets valued over $5 million will follow the standard method which allocates AoB *'charges based on each customer's positive expected net benefit, or a measure of physical capacity or average injection, to the extent that the expected net benefit approach was not practicable'* (TPM2 p xix). The 'Results_20160517b' spreadsheet released by the EA with TPM2 show the AoB charge for existing assets (total of $271m) is allocated using two methods:

- benefit shares by node calculated using vSPD modelling of the effect of the removal of the asset recovery cost ($243m)
- 'coarse' allocation of the asset recovery cost to generation or load customers in a geographical region followed by a fine allocation to nodes in the region using share of historical AMD for load customers and historical average injection for generators.

document. Therefore the totals for EDBs and industrials do not add to 100 percent for TPM2.

Table 1 Comparison of residual charge allocators for EDBs

TPM1 deemed capacity for EDBs and AMD for industrials compared to TPM2 AMD for 2014

Customer	TPM1	TPM2	Difference
Alpine Energy	1.66%	1.81%	0.14%
Aurora Energy	4.27%	3.62%	-0.65%
Buller Electricity	0.22%	0.32%	0.10%
Centralines		0.23%	
Counties Power	1.83%	1.45%	-0.38%
Eastland Network	1.21%	0.66%	-0.55%
Electra	1.96%	1.10%	-0.85%
Electricity Ashburton	1.13%	2.25%	1.12%
Electricity Invercargill		0.63%	
Horizon	1.14%	1.08%	-0.06%
Lakeland Network		0.03%	
Mainpower	1.71%	1.45%	-0.26%
Marlborough Lines	1.26%	0.87%	-0.39%
Network Tasman	2.27%	1.83%	-0.44%
Network Waitaki	0.66%	0.73%	0.07%
Northpower	2.47%	1.57%	-0.89%
Orion	9.28%	8.37%	-0.91%
OtagoNet JV		0.84%	
Powerco	14.60%	11.21%	-3.39%
PowerNet	3.07%		
Scanpower	0.31%	0.18%	-0.13%
The Lines Company	1.07%	0.87%	-0.20%
The Power Company		1.78%	
Top Energy	1.37%	0.82%	-0.54%
TrustPower		0.09%	
Unison	5.48%	3.92%	-1.56%
Vector	26.16%	24.97%	-1.20%
Waipa Power	1.12%	0.88%	-0.24%
WEL	4.14%	3.28%	-0.85%
Wellington Electricity	8.33%	6.72%	-1.61%
Westpower	0.68%	0.85%	0.17%

Total	**97.39%**	**84.43%**	**-12.96%**

Source: NZIER analysis of EA data

Table 2 Comparison of residual charge allocators for industrials

TPM1 deemed capacity for EDBs and AMD for industrials compared to TPM2 AMD for 2014

Customer	TPM1	TPM2	Difference
CHH	0.18%	1.01%	0.83%
Daiken MDF	0.02%	0.13%	0.10%
Fonterra	0.02%	0.15%	0.13%
Kiwirail	0.04%	0.42%	0.39%
Methanex	0.02%	0.11%	0.09%
Norske Skog	0.25%	1.30%	1.05%
NZ Steel	0.36%	1.94%	1.59%
Pacific Aluminium	1.31%	6.63%	5.32%
Pacific Steel	0.12%	0.00%	-0.12%
PanPac	0.18%	0.97%	0.79%
Rayonier	0.02%	0.10%	0.08%
Refinery		0.41%	0.41%
Winstones	0.09%	0.44%	0.35%
Total	**2.61%**	**13.63%**	**11.01%**

Source: NZIER analysis of EA data

In Section 3.1 AoB and residual charges there is a more detailed comparison of the shift from RCPD to AMD as an allocator and alternative allocators for EDB share of costs (deemed capacity per ICP type and EDB transformer capacity.) A quick summary of the indicative comparison based on the 2014 dataset is:

- the change from RCPD (N=100 for all regions) to AMD:
  - reduces the allocation of cost to EDB nodes by about 0.9 of a percentage point to 84.4 percent and industrial nodes by about 0.7 of a percentage point to 13.8 percent
  - increases the allocation to generator nodes by about 1.6 percentage points to 1.8 percent
- the TPM1 approach allocated between 93 and 97 percent of the residual costs to EDBs.

2.2.2. RCPD charge in regions with strong growth

i) In regions with forecast strong demand growth is the existing RCPD charge a problem? [10]

The EA proposal to replace the RCPD charge with a combination of AoB and residual charges allocated using share of AMD appears to be focused on using an easily calculated objective 'measure' of consumer use of grid capacity that can be readily applied to both EDBs and industrial consumers. (A key weakness with the deemed capacity measure proposed for TPM1 was that it was not based on measured data.)

Conceptually the coincident peak demand (CPD) is a better measure of consumer use of the grid that may require additional investment in the grid than AMD because CPD measures the peak use of the grid.[11] AMD does not distinguish between access to the grid during periods of high or low demand and therefore captures consumers who make their maximum use of the grid when it is less heavily used overall.

One of the objections to the RCPD charge is that the regions are defined broadly and the charge 'covers' all assets within a region so that the charge is not able to allocate cost to users according to their benefit from those assets. On this criterion the AMD based allocation cost would seem to be less efficient than RCPD as it allocates cost nationally and also away from consumers that contribute to the peak demand to consumers that do not. Arguably the allocation of the residual charge creates a price signal in the opposite direction to that intended by the AoB. In the time available we have not been able to model the potential net effect of these two signals but some more detailed thinking about this issue would be a useful cross-check on the net efficiency gains expected from a move to the TPM2 hybrid of AoB with allocation of a large residual using AMD.

TPM2 appears to compare the proposed change with the current status quo. As explained above we estimate that Transpower's proposed change in RCPD measurement to N=100 periods for all regions will make the allocation cost between EDBs as a group and industrials as a group about the same under AMD and RCPD. However the AMD and RCPD measures produce quite different cost shares for individual EDBs and industrials.

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10 *May need to expand this from just a hypothetical example to demonstrate a real problem. May be a problem getting regional forecasts as opposed to national demand forecasts – the latter tend to be flat. MEUG 2 TOR for NZIER advice on TPM and DGPP 27 May 2016*

11 In simplistic terms the grid needs to be built with sufficient capacity to meet anticipated peak demand. This can be thought of as two components; expected peak demand based on a combination of experience and forecasts plus an assessment of how many consumers will simultaneously exercise their option to access the grid to the full capacity of their individual connection. The RCPD charge focuses on historical use to allocate the cost recovery of assets and is one end of the spectrum of possibilities. The deemed capacity allocator proposed in TPM1 and the transformer or lines capacity allocator options proposed in TPM2 are focused on the recovering the cost of the optional capacity that the customer could access. An advantage of charging for the capacity option over actual use is that it provides a clearer signal to consumers about their contribution to the capacity required in the grid. However it is more difficult to calculate a capacity based allocator than an electricity use based allocator as:

- some industrial and commercial capacity will include business continuity capacity that is intended to provide back-up for the failure of a transformer or line that is used regularly
- consumer capacity is only fully accessible if the all the elements that connect the consumer to the generator can accommodate the consumers full use of their connection capacity. As an example, the deemed capacity of EDB connections proposed in TPM1 exceeded the transformer capacity of some EDBs and therefore the optional capacity available to consumers was lower than their deemed capacity.

The EA proposal to use an historical allocator that is not varied over time nullifies the value of either the RCPD or the AMD charge as a signal to consumers to change their use of electricity at peak periods. We cannot find any indication that the Oakley Greenwood CBA considers the potential effect of the loss of this signal as a moderator on industrials avoidance of peak load and therefore the potential that future peaks may will be higher or longer which may require additional investment in the grid.

The Oakley Greenwood CBA does not appear to directly consider the effect of change on transmission prices on the use electricity by industrials connected directly to the grid or the transmission charges paid by industrials directly connected to the grid.[12]

2.2.3. Investment to avoid RCPD

> *ii) What is the CBA treatment in terms of problem definition where load has invested or operated to avoid RCPD only to find that with grid investment in that region there is no foreseeable congestion?*

The CBA does not directly quantify the effect of current investment to reduce load at RCPD periods let alone whether or not this investment has proven to be viable. TPM2 discusses the need to avoid 'inefficient' demand response. However the CBA itself does not seem to explicitly assume any retirement of distributed generation or demand response. The CBA uses the Ministry of Business, Innovation & Employment's (MBIE) model for identification of new generation in responses to an assumed increase in capacity demand adjusted for the closure of Otahuhu. We do not believe that this model provides for the retirement or reduced use of distribution generation.

In general, the TPM2 approach to include the demand response and cogeneration in the gross AMD allocator seems to need clarification particularly with respect to the guidance given to Transpower to design the TPM. The TPM2 document clearly states that gross AMD should include demand response and cogeneration for example:

> *To the extent practicable and to the extent that the transaction costs of doing so would not be prohibitive, gross anytime maximum demand must be anytime maximum demand, including electricity generated by generation connected to the customer's network, demand-side management and demand response.*[13]

However this approach seems to be inconsistent with both the efficiency objectives of TPM2 and the EA calculations of the effects of TPM2 (Results_20160517b spreadsheet and the Oakley Greenwood CBA) as well as being potentially difficult to implement.

The EA spreadsheet 'Results_20160517b' does include gross and net AMD numbers by node in cells BH27:BI257 of the 'Rev Adequacy' worksheet. However these are hard

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12 Interconnection charges are analysed in the EA spreadsheet '988556_1_CBA Model - NZ EA - Final 10 May' at the following worksheet tabs:

- 'Proportion of IC Charge – Interconnection and Transmission charges'; which lists the interconnection transmission charges paid by EDBs and allocates these to the four Transpower regions provides input to the next worksheet 'Proportion of Retail'. Although the estimated transmission charges for direct connect industrials are also listed in this worksheet, they are not used as inputs for any subsequent calculations
- 'Proportion of Retail' which converts the interconnection charges paid by EDBS into an estimate of the proportion of retail electricity bills (using the assumption that 50 percent of retail bills are 'volumetric'). This proportion is used as input into the worksheet 'Status Quo Calculations (LC)' which in turn is used along with an elasticity assumption to estimate the response of electricity demand to a change in prices.

13 TPM2 p118, paragraph 7.183.

coded numbers with no formulae linking the columns and with values in the two columns that are equal or almost identical for nearly all nodes attached to load customers. (The gross AMD numbers listed in the EA spreadsheet for each load customer node seem to be about 95 to 96 percent of the gross AMD for 2014 calculated from the EA wholesale market file 'Generation_load_and_prices'.)[14] These comparisons suggest that the gross AMD numbers used in the EA spreadsheet have not been adjusted for demand response or distributed generation. Similarly the Oakley Greenwood CBA does not seem to include any specific adjustment for demand response or cogeneration in the allocation of residual cost.

The definition of gross AMD suggested in TPM2 is also likely to be difficult to implement as it would require all direct connect customers to provide accurate data on their historical use of demand response and embedded generation and presumably some evidence to verify this data.

EA analysis of nodal prices

> *iii) Is the EA's analysis correct that nodal prices are sufficient to incentivise optional generation investment and load investment as well as operation? This is important because it links with the proposal to use AMD as the denominator for charging residual and AoB and the latitude that Transpower may have to adjust the capacity measure over time. Also it would be good to have NZIER look at the potential effects their TPM proposal will have on spot prices.*

The discussion of nodal prices as a signal of the need for transmission investment in TPM2 seems to be focused on the extent to which this signal is 'undermined' by the current RCPD approach. (Nodal pricing and RCPD charges are both affected by coincident demand but RCPD aggregates nodal price signals over a region effectively 'averaging; nodal pricing signals.)

We have found it difficult to match TPM2 discussion of the value of nodal prices as a local signal of network congestion with any significant role for nodal pricing as TPM2 cost allocation method. To the extent that there is an increased role for nodal pricing it is likely to be in the vSPD modelling completed by the EA as an input to the CBA assumptions. However this influence does not appear to be quantified in the CBA assumptions.

In theory nodal prices should provide a signal of the increasing local congestion of parts of the grid. However our initial analysis of nodal price data suggests that:

- the average differences in nodal prices are usually a small percentage of the wholesale electricity price
- during periods of peak coincident demand, generation is also likely to be operating near capacity so that the nodal price and generation capacity signals merge into one price signal from the perspective of most consumers.

[14] Available at 'http://www.emi.ea.govt.nz/Datasets/download?directory=%2FDatasets%2FWholesale%2FFinal_pricing%2F2014_Generation_load_and_prices.csv

Our assessment is that the TPM2 guidelines emphasise two key constraints on Tranpsower's discretion to vary the residual charge allocator. TPM2 suggests:

- the allocator should be based on a historical measure to minimise the ability of consumers to change avoid the residual charge by changing their consumption patterns
- the same allocator should be applied to both EDB consumers and direct connect industrials[15] (in contrast to the approach used in TPM1 of capacity being assessed as AMD for industrial direct connects and deemed capacity for EDBs).

The use of an historical allocator without clear provision for adjusting the allocator over time[16] in response to either changes in usage by individual consumers or optimisation of AoB charges introduces a rigidity[17] into the allocation of the residual that may make the methodology less durable.

TPM2 analysis of the potential effects of the approach to allocating the residual charge is based on the AMD allocator for 2014 data. However the TPM2 document suggests the AMD allocator should be based on

> *transformer capacity in the year prior to the publication of this paper, line capacity in the year prior to the publication of this paper, or gross anytime maximum demand (gross AMD) in the 5 years prior to publication of this paper.*[18]

The reasons for the EA limiting its illustration of the proposed residual charge allocation to a subset of one of the potential allocators do not appear to be stated in TPM2.

We have not yet been able to estimate the potential effect of TPM2 on spot prices. To the extent that TPM2 reduces the incentives for industrials to avoid RCPD peaks and as the thrust of the TPM2 proposal is to encourage use of the grid, the bias of TPM2 is toward increasing spot prices in peak periods. However the TPM is only a secondary factor in the decision by the consumer on how much power to consume. Also this bias may be partially offset by the effect of a transmission price increase on retail and commercial consumers.

2.2.4. Recent change in HVDC charge

> *iv) With the recent change in HVDC charging are there any remaining problems? This will require understanding what assumptions the EA have made on how much of the current HVDC costs SI generators will be able to pass on under the future BAU scenario (transitioning from $/MW to $/MWh over 4 years starting 1 April 2017); the EA's justification of the Pole 2&3 benefit split*

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15 TPM2 includes nodes for the 'Refinery' in the list of industrials unlike TPM1.

16 The deeper connection charge.

17 A deeper connection charge based on 5 year rolling average of electricity flows is considered in TPM2 as an alternative to the AoB charge.

18 TPM@ pages xix to xx. On p xxvi, paragraph 120 the EA suggests that if gross AMD is chosen

> *'that Transpower consider whether gross AMD should be the highest gross demand over the five-year period, the average of the highest gross demands for each of the five years, the average of the 5 highest demands during the five-year period or some other average over the five-year period.'*

between generation and load; and how all this has been taken into account in the Oakley Greenwood CBA.

The TPM2 assessment is that the proposed changes to the HVDC link are still not optimal with the introduction of the SIMI charge. The EA assumption about how much of the HVDC charge South Island generators are able to pass on under the business as usual scenario is not clearly stated in the TPM2 paper. The net effect of the TPM2 proposal is to lower the annual transmission costs for South Island generators by about $110 million and is the clearest indicator of what is seen as efficient by the EA is the AoB reallocation of the HVDC assets.

The Oakley Greenwood CBA does not perform any additional analysis on the changes to the HVDC charges but simply takes the SIMI model output from the EA along with the Oakley Greenwood variations on the planned new generation plant forecast by the MBIE model. The old and new schedules seem to have similar orders of magnitude with small timing differences that deliver a small difference in net present value.

2.3. Other feasible options

b) Have other feasible options been considered? For example:

TPM2 is a simplification of TPM1 and therefore narrows the types of charges from the TPM1 combination of a deeper connection, AoB residual charge to just an AoB charge and an expanded residual charge. The Oakley Greenwood CBA compares the deeper connection and AoB options and finds that under the assumptions used the options have similar net present values but goes on to argue in favour of an AoB charge on the basis of simplicity.

The TPM2 analysis discusses the rationale for the key decisions of the use of an AMD indicator and the emphasis on use of historical allocators but does not include an explicit CBA of the decisions to:

- use AMD as an allocator instead of RCPD or the hybrid of AMD for industrials
- use a historical measure of AMD without any consideration of how the AMD[19] allocator may need to be adjusted over time.

The analysis also does not seem to consider how the removal of incentives to avoid RCPD periods may lead to more intense peaks in grid use. (Presumably the EA is relying on rises in nodal prices to replace the RCPD charge as an incentive to avoid RCPD peaks.)

2.3.1. Diesel generators

i) Is the assumption diesel generators would be the next cheapest transmission alternative correct?

[19] The AoB charge contemplates the need to adjust for new entrants and to adjust for the optimisation of existing assets but does not consider how to address changes in demand patterns between different users.

The Oakley Greenwood CBA of removing the RCPD delivers about $90 million of the net present value of net benefits from the TPM2 proposal. The benefits are dependent on the comparison of:

- the sum of estimated producer surplus from distributed generation and the use of a 50:50 mix of demand response and diesel generation[20] to meet part of the growth in peak demand
- the long run marginal costs of expanding the grid to deliver their proportion of the growth in the capacity.

This results in the comparison of two large numbers with a small positive difference which is mainly due to the cost of diesel generation. The assumed[21] expansion in the diesel generation over the 20 year forecast period does not seem to be consistent with either recent generation patterns or the planned and proposed future generation plants.

If the increase in diesel generation/demand response capacity required in the CBA is achieved solely by demand response this part of the CBA would deliver a net present value of $-54 million indicating that positive value attached to removing the RCPD in the Oakley Greenwood CBA is subject to a wide margin for error.

2.3.2. Why change HVDC

ii) If the recent operational changes to HVDC charging have overcome all problems with the existing HVDC allocation why not keep existing HVDC assets separate?

TPM2 argues that even with movement to the SIMI charge that the cost of using the HVDC cable would still encourage inefficient investment in small-scale North Island generation. However the net present value of removing the HVDC charge (as estimated by Oakley Greenwood) is modest at $13 million over 20 years.

2.4. Is TPM2 the best option?

c) Has the best feasible option been proposed?

The CBA analysis does not provide compelling evidence that the best option has been chosen for the following reasons:

- the value of the net benefits is small in comparison to both the transmission costs and the cost and benefit streams modelled suggesting that the positive result is sensitive to the assumptions. In particular the two main contributors to the positive value of the CBA have the following weaknesses:
  - the benefit from the replacement of the RCPD with an AoB charge ($89 million) relies on a substantial increase in diesel generation – if this is

[20] The assumption used is that diesel generation and demand response both increase over a twenty-year period until they reach a 5 percent cap of the required capacity with the demand response costing about $200 per MWh and the diesel generation costing about $1,200 per MWh.

[21] The assumed expansion for both the demand response and the diesel generation is that these should each reach 5% of total capacity over 20 years. The use of a 50:50 mix is surprising as the cost of demand response is less than 20 percent of the cost of diesel generation.

replaced with reliance on demand response the net present value of the removal of the RCPD is negative

  - the benefit from more efficient generation investment ($92 million) relies on Oakley Greenwood re-ordering the implementation sequence of two sets of new generation plants that are almost the same. We have not been able to confirm the decision rule used to change the implementation order.[22]

- the increase in capacity[23] used in the CBA seems to be high compared to recent experience and also Transpower forecasts, (however some of this may be explained by differences in start dates[24])
- the net present value of the deeper connection option is similar to the net present value of the AoB option suggesting it is credible alternative even with its increased complexity.

i) Does the proposal overcome the stated problems better than any other feasible option?

See above response to c). Futhermore, the Oakley Greenwood CBA estimates that the net present value of the benefits of the deeper connection charge option are almost the same as the estimated net present value of the AoB charge option (preferred by the EA.) The EA argues against the deeper connection on the grounds that it would it less efficient than the AoB charge[25] because the deeper connection charge allocates cost on the basis of use of assets rather than benefit from the assets.

ii) Are there any unintended consequences not considered in the paper?

The main unintended consequence likely to emerge from TPM2 is future pressure to change the method of allocating the residual caused by the use of cost allocators based on historical measures without any clear description of a mechanism of how these allocators will be adjusted to respond to changes in future demand patterns.

Secondary unintended consequences are likely to include:

- potential uncertainty about transmission cost allocation between areas as the process for optimisation of assets is implemented and used
- an increase in the intensity of peaks as the incentive for consumers to avoid peaks is weakened by the removal of the RCPD based charges.

iii) Is the conclusion that that the CBA for the proposal is positive under all scenarios robust?[2][26]

Although the net present value for the changes modelled by Oakley Greenwood is likely to be positive in most cases we expect that it will be much lower than the $200 million estimated by Oakley Greenwood.

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22 The CBA spreadsheets use formulae that have been entered manually rather than the result of a decision formula in the spreadsheet. We still need to do some more work to confirm the decision rule used in the CBA.

23 The relationship between required generating capacity and demand peaks are not clearly stated and seem to vary.

24 The CBA uses a mix of 2016 and 2019 start dates.

25 TPM2 p160-161, paragraph 8.52.

26 2 Paragraph 8.16, table 5, p154.

3. Specific charges

3.1. AoB and residual charges

d) Questions relevant to both AoB and residual charges:

i) Over the CBA time horizon what is the expected ratio of AoB to residual charges given continuous annual capex replacement (~$200m pa) will be charged at AoB?

As a lead-in to answering this question it is we briefly describe the main reallocation effects achieved by the AoB charge and compare this reallocation to the reallocation that would occur if these costs were reallocated using the AMD allocator. We focus on the reallocation between EDBs, direct connect industrials and generators as a group rather than the reallocation between customers within each of these groups. As noted earlier in this report, the AoB charge covers about $290 million of which about $243 million are allocated using vSPD estimates of the share of benefit to both load and generation customers that use these assets. The other $40 million of AoB charges is reallocated to a subset of mainly load customers based on their relative shares of AMD.

Of the $243 million of costs allocated using vSPD modelled benefit shares, the cost recovery for two assets,[27] Pole 2 in particular and Pole 3 to a lesser extent drives the bulk of the reallocation of AoB charges from EDBs and industrials to South Island generators.

TPM2 seems to suggest that the AoB charge will displace the residual charge (excluding overheads) over time as Transpower invests in new assets for which the benefits can be allocated to a particular group of customers but does not seem to include an estimate of the speed at which the AoB charge will increase. TPM2 seems to use a multiple of 15 percent[28] of the cost of the asset as an estimator of the impact of Transpower capital expenditure on Transpower's revenue requirement. We combine this multiplier with data from the Transpower Integrated Transmission Plan[29] to provide an indicative high and low side estimate of how quickly the residual charge (excluding overheads of $197 million) could be replaced by the AoB charge over the period 2015 to 2025 – revenue control period 2 (RCP2) and revenue control period 3 (RCP3).

A high side estimate of the potential increase in the AoB charge is 15 percent of the major and base capital expenditure over RCP2 and RCP3. As projected capital expenditure over RCP2 and RCP3 is approximately $3,420 million, the high side

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27 The annual asset cost recovery based on the vSPD modelling are: North Island Grid Upgrade (NIGU) - $85m , HVDC link Poles 2 - $45m and 3 - $73m, North Auckland and Northland grid (NAaN) - $20m, LSI Renewables (LSIren) - $4m and Wairake Ring - $15m.

28 For example see TPM2, Table 3: Incidence and allocation of post-2004 approved investment, p61

29 The key Transpower documents are:

- 'Integrated Transmission Plan 2015' section 8.2 and 8.3 p30 to 37 available at https://www.transpower.co.nz/sites/default/files/plain-page/attachments/TP%20AMP%202015.pdff
- RT06 - Integrated Transmission Plan spreadsheet available at https://www.transpower.co.nz/node/10951/regulatory-templates

estimate would be that the residual charge (excluding overheads currently $197 million) would be almost fully displaced by the AoB charge within RCP3.

A low side estimate of the potential medium term reallocation of cost recovery due to the switch from residual to AoB charge would be an increase of $127 million by 2025 based on the recovery of the costs major capex projects for RCP2 and RCP3 that can be allocated to an area. Major capital expenditure over RCP2 and RCP3 is projected by Transpower to be $1,016 million of which $168 million does not appear to be allocated to a particular area. Table 3 below lists the planned major capital expenditure and the region to which cost recovery could be allocated.

Table 3 Integrated Transmission Plan

Approved and planned major capital expenditure over 2015 to 2025 (RCP2 and RCP3) in $ million

Description	RCP2	RCP3	Total
Upper North Island dynamic reactive support	11		11
Pakuranga-Whakamaru series compensation	50		50
Upper North Island voltage stability		60	60
Upper North Island	**61**	**60**	**121**
Reconductoring Haywards to Bunnythorpe (6 projects)	235	57	292
Lower North Island transmission reinforcement	20	75	95
Lower North Island	**255**	**132**	**387**
Upper South Island grid upgrade - stage 2		58	58
Lower South Island reliability	15		15
Clutha-Upper Waitaki lines programme	89		89
Waitaki Valley	20		20
Lower South Island	**124**		**124**
HVDC stage 3		**52**	**52**
Unidentified reconductoring projects		**168**	**168**

Source: Transpower Integrated Transmission Plan

The timing and location of planned major capital expenditure suggest that the lower North Island region will have the largest and quickest shift from the residual to AoB charge. The overall timing of the shift of cost recovery from residual to AoB charge is difficult to predict nationally let alone for individual 'areas' using the high-level information base capital expenditure contained in the asset management plan. However the speed of the transition is likely to vary from area to area due to differences in both the age of assets and changes in demand in individual areas.

The TPM does not appear to state explicitly how the increase in AoB charges in a given area would affect the obligation of consumers in that area to contribute to the national residual charge. Given that the residual charge is allocated using a historical allocator two 'extremes' of the possible interpretations of the application of the reduction in the residual charge following an increase in the AoB in a given area are:

- the reduction in the residual charge is applied at the national level so that consumers in the area where the AoB has increased receive part of the reduction in the residual charge depending on their share using the historical allocator
- the reduction in the residual charge is applied in full to the customers in the area that are affected by the increase in the AoB charge which means that the historical allocator for the residual charge is effectively changed for this area.

The mirror image of this residual reallocation problem will arise for in future for assets that are optimised under the provisions in the guidelines.

The shift of cost recovery from the residual to the AoB charging bucket provides little information on the change in the cost of allocation for industrial users as the geographical spread of the AoB charge is not known. Unless vSPD modelling or one of the other alternatives for benefit assessment is used to allocate residual charges that that have been converted into AoB charges the allocation of these new AoB charges may be similar to their allocation when they were a residual charge.

> *ii) What alternative denominators apart from AMD could be considered? Does a national AMD adequately cover specific regions where the risk of congestion is increasing? Put another way a RCPD, where "R" is regional is a good approach for a regional price signal whereas AMD mutes the signal. This is related to the question of will the nodal prices deliver a sufficient signal to encourage some level of peak management, or will it be a matter of a LRMC signal at the appropriate time? Also consider the pros and cons of Transpower contracting through the demand response programme for regions where congestion is starting to become an issue.*

TPM2 considers transformer capacity and lines capacity as alternatives to the AMD while TPM1 considered deemed capacity for EDBs and AMD for large industrials. We do not have access to data on the transformer capacity of industrials however we estimate that if we used:

- a hybrid of the AMD for industrials and deemed capacity for EDBs with a residential capacity of 10 kW per household (rather than the 20 kW used in TPM1) the cost share allocator for EDBs would be above 90 percent
- a hybrid of the AMD for industrials and maximum transformer capacity of EDBs the cost share allocator for EDBs would be about 90 percent.

A comparison of the cost shares using AMD as stated in TPM2 and our estimate of shares based on estimated RCPD for 2014 is shown in Table 4 for EBS and Table 5 for industrials.

Table 4 EDB cost shares based on AMD and RCPD

TPM2 AMD and estimated RCPD at N=100 for all regions for 2014

EDB	AMD	RCPD	AMD less RCPD
Alpine Energy	1.81%	1.48%	0.33%
Aurora Energy	3.62%	3.99%	-0.36%
Buller Electricity	0.32%	0.22%	0.10%
Centralines	0.23%	0.28%	-0.05%
Counties Power	1.45%	1.48%	-0.03%
Eastland Network	0.66%	0.80%	-0.14%
Electra	1.10%	1.26%	-0.16%
Electricity Ashburton	2.25%	0.92%	1.33%
Electricity Invercargill	0.63%	0.75%	-0.12%
Horizon	1.08%	1.13%	-0.05%
Lakeland Network	0.03%	0.04%	0.00%
Mainpower	1.45%	1.30%	0.15%
Marlborough Lines	0.87%	0.93%	-0.06%
Network Tasman	1.83%	2.04%	-0.21%
Network Waitaki	0.73%	0.50%	0.23%
Northpower	1.57%	1.87%	-0.29%
Orion	8.37%	8.84%	-0.47%
OtagoNet JV	0.84%	0.88%	-0.04%
Powerco	11.21%	11.47%	-0.26%
Scanpower	0.18%	0.21%	-0.03%
The Lines Company	0.87%	0.73%	0.14%
The Power Company	1.78%	1.68%	0.10%
Top Energy	0.82%	0.96%	-0.13%
TrustPower	0.09%		0.09%
Unison	3.92%	4.46%	-0.54%
Vector	24.97%	24.69%	0.28%
Waipa Power	0.88%	0.89%	-0.01%
WEL	3.28%	3.39%	-0.11%
Wellington Electricity	6.72%	7.56%	-0.84%
Westpower	0.85%	0.56%	0.28%
Total	**84.43%**	**85.30%**	**-0.87%**

Source: NZIER analysis of EA data

Table 5 Industrial cost shares based on AMD and RCPD

TPM2 AMD and estimated RCPD at N=100 for all regions for 2014

EDB	AMD	RCPD	AMD less RCPD
CHH	1.01%	1.02%	0.00%
Daiken MDF	0.13%	0.12%	0.01%
Fonterra	0.15%	0.04%	0.11%
Kiwirail	0.42%	0.08%	0.35%
Methanex	0.11%	0.09%	0.02%
Norske Skog	1.30%	0.31%	0.99%
NZ Steel	1.94%	1.70%	0.25%
Other	0.15%	0.23%	-0.08%
Pacific Aluminium	6.63%	8.71%	-2.08%
Pacific Steel	0.00%	0.48%	-0.48%
PanPac	0.97%	0.65%	0.32%
Rayonier	0.10%	0.09%	0.01%
Refinery	0.41%	0.49%	-0.08%
Winstones	0.44%	0.43%	0.01%
Total	**13.78%**	**14.44%**	**-0.66%**

Source: NZIER analysis of EA data

3.2. AoB charges – specific questions

e) Questions on the AoB charge:

i) Q1 in EA paper: For new investments the EA used a $5m threshold between using a standard AoB method (more granular for high value investments) or simple AoB method (for lower value investments). What should the threshold be?[30]

The key question for the choice of threshold is whether the more granular method based on the share of benefits from AoB assets as opposed to the AMD cost share allocator can actually be applied to new AoB assets. A discussion of the guidelines for when and how a share of benefit approach could be used would be more helpful than setting a dollar threshold. It would also be useful for the EA to devise a test based on

[30] 3 Paragraph 7.72, p97. First of 4 specific questions in the paper.

whether the AoB allocation is likely to be materially different from the residual charge allocation.

> *ii) Q2 in EA paper: Which of 5 alternative methods to calculate standard AoB should be used or are there other approaches?*[31]

It is difficult to answer this question without a more detailed description and examples of the application of the 'Area of Influence' and 'Balanced Scorecard' options along with clarification of the types of benefit (electricity price, reliability etc) considered by each method. We suggest that:

- the EA provide an assessment of each of the alternative methods against its decision-making principles
- Transpower as part of its development of a transmission pricing methodology, provide examples of the application of these methods to assess both the materiality of the differences in the results produced by each method and also the range of variation in the results for each of the methods.

> *iii) Q3 in EA paper: Which of 3 alternative methods to calculate simple AoB should be used or are there other approaches?*[32]

See above.

> *iv) Is there benefit in expanding existing assets covered by AoB method or is there an equal downside with the re-allocation to the residual?*

The shift of cost recovery from the residual to the AoB charging bucket provides little information on the change in the cost of allocation for industrial users as the geographical spread of the AoB charge is not known and the cost share allocator for the AoB charge is effectively the same as the cost share allocator for the residual charge.

> *v) Can the guidelines be strengthened to require more transparency on assets optimised out of being charged using AoB and re-allocated to the residual?*

Yes the guidelines need to be strengthened as the present version gives almost no visibility on how the process would work, which parties can request optimisation and the threshold for wider consultation about the potential reallocation. In particular it is unclear how the interests of t

> *vi) What policy tool(s) are available to ensure prospective and actual AoB charges can be made transparent to all classes of consumer in order to increase participation in gauging the benefit of a new investment proposal or alternatives or the value of avoiding existing grid assets?*

[31] 4 Paragraph 7.80, p99. Second of 4 specific questions in the paper.

[32] 5 Paragraph 7.81, p99. Third of 4 specific questions in the paper. MEUG 3 TOR for NZIER advice on TPM and DGPP 27 May 2016

The main policy change that would be helpful would be encouraging EDBs charging of customers for capacity rather than volume of electricity used. Without this change a large part of the market does not receive any AOB charge signal.

3.3. Residual charges – specific questions

f) Questions on the residual charge:

i) Q4 in EA paper: Any preference for residual-based or surcharge-based approach or some variant for recovery of overheads and unallocated operating costs?[33]6

Ideally the first priority should be to identify beneficiaries of the unallocated operating costs. If this option is not available then alternatives of a surcharge or other options should be left as question to be considered in the design proposed by Transpower.

ii) Is there any information to assist identify unused and useless asset values? A long shot because in an integrated grid even using an overbuilt asset such as NIGUP in one trading period justifies that historic expenditure. Nevertheless worth keeping a watch for anything to assist MEUG's argument Transpower's shareholders should be partly accountable for poor historic investment decision making.

The TPM2 does not include information on the extent to which existing assets are underused. The optimisation process for the AoB charge does provide a process for underutilised assets to be identified and the recovery of the cost of these assets to be transferred to the residual charge. However, the EA proposes that optimisation can only be considered after assets have been commissioned for 10 years (unless the optimised replacement cost (ORC) falls by more than 20 percent due to the disconnection of a major customer or the ORC falls below 80 percent of the replacement cost. (TPM2 does not discuss the application of these tests to existing assets.)

iii) Can the guidelines be strengthened to require Transpower to allocate currently un-allocated operating costs? Are there any other components of the residual that could be specifically allocated rather than use AMD?

Comments by EA representatives at presentations of TPM2 suggest that the EA has already asked Transpower to assess whether any of the remaining un-allocated costs can be allocated to particular assets and whether the residual charge can be reduced.

[33] 6 Paragraph 7.220, p125 following discussion starting p122. Fourth of 4 specific questions in the paper.

4. PDP and DG

4.1. Prudent discount policy

g) Questions on the PDP:

i) Should TPNZ, EA or some other party make final PDP decision?[34]7

The decision should be made and monitored by a regulator such as the EA.

ii) Given a robust and easily implementable PDP is critical should the proposal be further developed what design aspects need to be considered?

Yes. The current proposal does not appear to be practicable given the high level of exposure to transmission costs required to qualify for a PDP or internally consistent – the value to other customers of the PDP recipient continuing to use the grid exceeds the cost to those customers of paying the grid use cost no longer paid by the PDP recipient.

4.2. Distributed generation paper

h) Questions on the Distributed generation pricing principles issues paper and CBA:

i) Does the explanation of the issues identified in the paper apply fully to cogeneration plants (as opposed to distributed generation in general)?

The distributed generation paper does not seem to clearly identify or distinguish cogen plants from distributed generation, while the Results spreadsheet used by the EA for TPM2 do not seem use cogen data in the allocation of costs.

The EA estimates that the reduction in avoided cost of transmission (ACOT) payments will have efficiency benefits with a net present value of $2 million to $20 million and benefits to consumers of $232 million to $325 million under the current TPM that these benefits would be considerably lower under the proposed TPM (as the AoB charge is expected to discourage the inefficient investment in generation encouraged by ACOT payments).

ii) Do the assumptions made in the CBA apply to cogeneration plants which are generally not connected to an EDB distribution system?

The TPM2 CBA uses estimates of EDB distributed generation but does not make any specific reference to cogen plants.

[34] 7 Paragraph 7.250, p131. MEUG 4 TOR for NZIER advice on TPM and DGPP 27 May 2016

iii) Review the assumptions made to calculate the four specific aspects of the CBA with a view to establishing if there is data or information available to arrive at a view as to how credible they are in particular over the 1-2 year period prior to the proposed introduction of the new TPM.

The four specific aspects of the CBA are:

- reducing inefficient, out-of-merit operation essentially diesel generators
- reducing the scope for retention of distributed generation that does not lower transmission investment costs does not provided other benefits
- reducing inefficient, out-of-merit investment in new distributed generation
- reducing the allocative efficiency losses from consumers paying higher prices for electricity and consuming less than they otherwise would.

The assumptions for aspects 1, 2 and 4 of the CBA seem to be reasonable and they make a small contribution to the annual benefit estimated for the proposal. The main driver of the benefit in the CBA is the third aspect, the avoidance of future investment in inefficient distributed generation and the key driver of this estimate is the credibility of the assumptions that 20 MW of new capacity would be constructed each year in the absence of the proposed change.