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# CROSS SUBMISSION: PROPOSED TRANSMISSION PRICING METHODOLOGY

## 1. INTRODUCTION AND OVERVIEW

### 1.1. Introduction

1.1.1. Thank you for the opportunity to provide a cross-submission on the Electricity Authority's 8 October 2021 Proposed Transmission Pricing Methodology (**TPM**) Consultation Paper (**Consultation paper**).

1.1.2. A total of 32 submissions were made on this Consultation paper. This is considerably less than prior consultations on this topic. This may suggest that stakeholders do not believe there is much opportunity 'to shift the dial' on the Authority's proposal.

1.1.3. There is some evidence of this in the submissions. For example, Network Waitaki said that at this point it views "*the proposed TPM as fait accompli*"[1] and New Zealand Steel said it had concluded:[2]

> " *the substantive aspects of a new TPM have long become fixed in the minds of the Authority and the remaining items open for genuine consultation are relatively minor points on the fringe*".

1.1.4. While we fully understand the fatigue, we hope these views do not reflect the reality.

### 1.2. Common concerns

1.2.1. Amongst the stakeholders still interacting in this process, are some common concerns which have not gone away. These include concerns about the:

a) complexity of the proposed TPM and uncertainty about the level of future charges;

b) disincentives for investment to support decarbonisation;

c) inconsistent/discriminatory treatment of transmission customers (including in relation to price caps and transitions);

[1] Network Waitaki sub, page 1

[2] NZ Steel sub, page 1

d) charges faced by individual transmission customers not actually reflecting the benefits or value received from the transmission system; and

e) impact on consumers of removing the RCPD charge.

1.2.2. These concerns mirror concerns we raised in our primary submission.

### 1.3. Contrasting views

1.3.1. In contrast to these views the Authority's TPM continues to receive support from its primary beneficiaries.

1.3.2. For example, Meridian Energy welcomes the removal of the HVDC charge and the shift to recognise new technologies especially batteries.[3]

1.3.3. Contact Energy also approves the "*general thrust of the TPM*"[4].

### 1.4. Design choices

1.4.1. In terms of the Authority's TPM design choices:

a) There is very limited support for the Authority's proposal to address anticipatory capacity for connection charges by further BB charging;

b) Stakeholders are also surprised by the 50:50 load: generation weighting for the simple BB method in the light of the evidence supporting a 75:25 load: generation allocation;

c) Submitters have outlined a number of features of the residual charge that have proved problematic in practice;

d) There is concern about the impact of trailing exit charges; and

e) The stand alone cost prudent discount is already proving problematic.

### 1.5. Compliance with section 39

1.5.1. No submission presented views contrary to those expressed in our primary submission on the Authority's alternatives analysis and cost benefit analysis (**CBA**).

1.5.2. There was some support from Mercury for our concerns on the CBA.

1.5.3. However, most submitters appear to have presumed rather than tested compliance with section 39. This may be further evidence of the fatigue noted earlier.

1.5.4. The remainder of this cross submission elaborates on those matters raised in sections 1.2-1.5 above.

## 2. COMMON CONCERNS

### 2.1. Complexity of TPM and uncertainty of future charges

2.1.1. In prior submissions we have explained that we think the complexity of this TPM and associated uncertainty about future charges will adversely impact future investment.

[3] Meridian Energy sub, page 1

[4] Contact Energy sub, page 2

2.1.2. Mercury also consider that uncertainty around transmission charges will inhibit required investment:[5]

> *"Currently, even large stakeholders like Mercury struggle to fully understand the workings of its proposed charges relating to existing transmission and generation assets, let alone estimating likely charges that may attach to future build. This adds risk to new generation and load developments, making it more difficult to attract capital investment needed to finance projects – the latter being a particular challenge for new entrants….*
>
> *For large generator-retailers, merchant generators and large loads alike it will become harder to make a solid business case for investments if reasonable estimates of future transmission charges are not straightforward. While transmission charges are only one component of an investment proposal (resource availability, site suitability, consenting, wholesale pricing, offtake contracts, et cetera are more important), the degree of uncertainty around the quantum of transmission charges currently makes these a disproportionate risk."*

2.1.3. Contact Energy, also has concerns with the complexity and uncertainty of the new regime:[6]

> *"The inability of stakeholders to calculate with any accuracy or certainty what transmission charges will be for them prior to a new investment creates its own source of inefficiency."*

2.1.4. Counties Power agrees and comments that:[7]

> *"Under the Proposed TPM Code, new major generation, or industrial plants will find calculating the benefit-based charges difficult and forecasting transmission charges near impossible. This will apply to both direct grid connection customers and major EDB load or generation customers where the EDB will pass this uncertainty through to the end customer. This cost uncertainty will negatively impact industrial investments for new industrial plants requiring significant amounts of power and for decarbonisation of industrial process heating. Generation investment will also be similarly negatively impacted."*

2.1.5. Orion said:[8]

> *"…we are concerned that assessments for successive upgrades will lead to a complex entanglement of benefit based assessments. This will undermine the purpose of the TPM in that the pricing outcomes for proposed upgrades will become very uncertain which will not drive efficient outcomes."*

2.1.6. Vector submitted:[9]

> *"…it is a concern that the long term and cumulative impact of price increases under the TPM remains unclear. This lack of transparency and the uncertainty it creates falls well short of regulatory best practice which the Authority should address before implementing the TPM."*

## 2.2. Disincentives for decarbonisation investment

2.2.1. Some submitters provided examples of specific project risks.

2.2.2. Oji Fibre Solutions submitted:[10]

> *"We note that the Authority has used the argument that changes to the TPM are required in order to promote new renewable generation. However, we make the observation that many of the Authority's proposed changes to the TPM will if anything, undermine Government policy and in particular act as a disincentive for new renewable generation. In particular, we note that the*

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[5] Mercury sub, page 1

[6] Contact Energy sub, page 4

[7] Counties Power sub, page 2

[8] Orion, sub page 7

[9] Vector sub, page 1

[10] Oji Fibre sub, page 2

*proposal creates a significant disincentive for OjiFS to invest in bioenergy infrastructure in the central North Island."*

2.2.3. Contact Energy's submission also outlines its experience of customers choosing to continue with coal rather than convert to electricity due to the uncertainty of future transmission costs under the new TPM.

## 2.3. Inconsistency and inequity in treatment of transmission customers across the TPM

2.3.1. The granularity of the new TPM means that inherent within its design are a number of bright line distinctions which transmission customers see as arbitrary and inconsistent.

2.3.2. Our most recent submission provided examples of inconsistent and inequitable treatment by stepping through the TPM from the perspective of different types of transmission customer.

2.3.3. Other examples are provided in the submissions on the Consultation paper.

### *Inconsistent treatment of embedded vs grid-connected load*

2.3.4. Some submitters commented on the inconsistent treatment of embedded vs grid connected load.

2.3.5. Network Waitaki, contrasts the Authority's concern that some connection customers may face charge increases of more than 10% under one of its proposed solutions for the FMD issue, with its lack of concern about the considerably larger prices increases embedded load will face under the new TPM without any protective price cap or transition. In its view:[11]

> *"The proposed transitional cap does not provide a level playing field for customers in terms of transitional measures benefiting some (large direct connect customers) and not others (large customers connected within distribution networks)."*

Network Waitaki also notes that its largest customer North Otago Irrigation Company;[12]

> *"…will face a transmission charge increase of 126% but also have to contribute to the transitional cap for other large users which is a very perverse and unintended outcome".*

2.3.6. Oji Fibre's submission also notes that it is unable to access the transitional cap despite an increase in charges of approximately 75% as it is also connected to the grid via a distribution network.[13]

2.3.7. Orion note the Authority have not considered the position of the large load within distributor networks many of whom will face inevitable price shock from this proposal:[14]

> *"When distributors look to reflect the new TPM in their charges to customers, the price shocks will not be avoided. In some situations, distributors will not be able to overcharge some customers in order to smooth the impact for others. Like Transpower, we too have individual consumers that have found ways to entirely or almost entirely avoid the RCPD charge.*
>
> *This is an inevitable outcome of change. An alternative and effective mitigating approach is to transition to the new TPM over a period of time, progressively deweighting the RCPD and HVDC charge and replacing it with the new charge components. With this approach the impact on individual customers is mitigated."*

2.3.8. We agree with Orion's suggested transitional arrangement to better manage price shocks. Price shocks for embedded load will not enhance this TPM's durability or provide incentives for further electrification of their business processes.

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[11] Network Waitaki sub, page 1

[12] Network Waitaki sub, page 11

[13] Oji Fibre sub, page 2

[14] Orion sub, page 3

### *Treatment of batteries vs other load*

2.3.9. The Authority's recent decision to treat batteries differently from other types of loads was widely commented on.

2.3.10. Fonterra said the proposed approach to the application of the residual charge for battery storage, is discriminatory relative to other electrical energy storage options:[15]

> *"Other energy storage forms could include, for example, thermal batteries where the input is electricity, energy is stored for some indeterminate period, and output as heat or cold. It is inefficient and not of benefit to consumers to be dis-incentivised from using the most economic technology available for electricity use. Fonterra submits that all electrical energy storage options need to be treated the same."*

2.3.11. Vector said:[16]

> *"Charging batteries based on gross energy rather than gross anytime maximum demand (as applied to other load customers) is discriminatory to load and may have distortionary effects. We consider it vitally important the new TPM is technology neutral across all customers.*
>
> *It is critical flexibility is encouraged in all its forms rather than bespoke pricing arrangements to different forms of flexibility (such as that offered by grid connected batteries). The Authority needs to develop a residual charge that is technology agnostic and provides appropriate incentives to all forms of flexibility."*

2.3.12. MEUG's submission observes that the proposed approach creates distinct advantages for battery storage in some markets:[17]

> *"The proposed solution is acceptable when a battery is being charged from the electricity-energy market and discharged into the same market. The proposed solution does not work when a battery is being charged in the electricity energy market and discharged into non-electrical-energy services markets. The latter includes frequency keeping, reserves, avoidance of line charges, mitigating line constraints, and in the future possible other yet to be designed ancillary services and alternatives to line services markets. Competitors to batteries in these non-electrical-energy services markets include large users that have an ability to shed load. These large users may be existing companies or potentially new entrant businesses with innovations in technology, processes or business models. Both existing and new entrant businesses will have initial residual charges set based on gross Any Time Maximum (AMD) whereas batteries competing in those non- electrical-energy services markets will have initial residual charges set based on the AMD of losses only, and not gross AMD including losses. "*

2.3.13. We agree with the concerns, noting that these effects do not sit well with the Authority's objective of promoting competition in the industry.

## 2.4. Concerns that the benefit based charges will not actually reflect net private benefits

2.4.1. A number of submitters are concerned that their initial cost allocations will not reflect the benefit they receive from the transmission system.

2.4.2. Federated Farmers said:[18]

> *"Claims that have been made to the effect that farmers in the north of Auckland are amongst the major beneficiaries of the relatively recent North Auckland and Northland (NAaN) grid upgrade and the North Island Grid Upgrade (NIGUP), claims which it is considered cannot be accurate. These upgrades were necessitated primarily by the large increase in urban electricity needs within metropolitan Auckland and, in the case of NAaN, most particularly on the northern outskirts of*

[15] Fonterra, page 3

[16] Vector sub, page 7

[17] MEUG sub, pages 3-4.

[18] Federated Farmers sub, page 3

*metropolitan Auckland. The claimed improvements in reliability that have also been made have not generally been seen in rural areas"*

2.4.3. Network Waitaki said the effect of the TPM will be

*"Large increases in charges with no extra benefit, for example the TPM changes for Network Waitaki increase transmission charges by 25% for the use of the wider national grid, however, still leaves us with an already constrained local transmission grid which requires further investment in the medium term."*

2.4.4. Mercury commented that the determination of benefits for the pre-2019 assets is inconsistent with economic theory and said:[19]

*"…any assessment is a modelling outcome rather than an objective exercise as evidenced by how the assessment of beneficiaries has shifted with various proposed TPM iterations".*

2.4.5. Others are worried about how modelling outcomes results will translate over time.

2.4.6. For example, the Unison submission highlights the inequities associated the reopeners which do not permit adjustments to the original allocations if the underlying assumptions change, such as for the CUWLP upgrade if Tiwai stays, or other load arrives in the South Island, so forecast benefits to North Island customers never materialise.

2.4.7. Unison observe that:[20]

*"…in the event that Tiwai does indeed stay, then load customers who disbenefit from the investment must continue to pay for the investment. This seems problematic and apt to bring the TPM into disrepute."*

Unison concludes that the CUWLP case study shows:[21]

*"…that material value differences can be driven by the determination of scenarios, scenario probabilities, factuals and counterfactuals and are likely to drive high levels of contention among potential beneficiaries."*

2.4.8. We continue to struggle to see how the Authority considers that such outcomes promote durability, the efficient operation of the industry and compliance with its pricing principle that 'you pay for what your get'.

## 2.5. The issues with the current RCPD have been overstated and risks of removal not properly evaluated

2.5.1. Orion submitted[22]:

*"The Authority's focus on short run marginal costs leads to a conclusion of inefficient response to RCPD signals. The alternative view is that long term pricing signals encourage a response in a very inelastic market, and that a response would otherwise not occur in the face of dynamically changing real time pricing. The observed volatility in RCPD charging could be addressed in a number of ways."*

2.5.2. NZ Steel's submission disagrees with the Authority's evaluation of the removal of a peak pricing signal in favour of a singular reliance on nodal pricing. It sees the removal of the RCPD charge as giving rise to problematic outcomes in both the short term and the long term.

In the short term it sees:[23]

[19] Mercury sub, page 3

[20] Unison sub, page 6

[21] Unison sub, page 8

[22] Orion sub, page 6

[23] NZ Steel sub, page 6

*"A lack of appropriate demand signals in the TPM will likely increase the occurrence of 'stress events' and we take exception to the suggestion that this can be effectively controlled through available tools in a way that "…limits load shedding." Invariably there is a direct or indirect impact on consumers and therefore a cost. We see no attempt by the Authority to measure this cost."*

In the longer term, it has concerns about the costs of not managing load:[24]

*"Power systems need to be designed and managed for peak load. Economic growth and electrification will see a significant increase in the requirement for additional generation and uprating of the grid and local networks. While there may be adequate capacity in most of the grid now, unmanaged growth will see increases in peak loads. The time congestion pricing clicks-in it is too late. Consumers will face the costs of then managing load until further investment is made in the grid, which again consumers pay for the cost, and in many cases will involve delays until the work can be completed."*

2.5.3. Oji Fibre also disagrees with the Authority on this topic. It sees the RCPD charge as[25]:

*"…an effective means for reducing peak demand and deferring grid investment. We agree that it is perhaps stronger than it needs to be, but that it has the desired effect and provides correct incentives for reducing congestion on transmission and distribution networks."*

Oji Fibre observes that[26]:

*"Electricity demand is highly inelastic, with significant amounts of load unable to respond to RCPD signals, and the majority of load also insulated from locational marginal pricing signals. Consequently, to move load from peak periods, a strong and predictable pricing signal is required for customers to respond."*

*2.5.4.* IEGA comment that[27]

*"Further, reliance on the spot price to influence behaviour during congestion may not be as effective as the Authority expects as Transpower states "The change in market price due to a constraint is not always the most significant factor in determining private benefits – the amount of time a constraint is expected to bind, and the volume of load or generation exposed to a change in price is often more important".*

*"The IEGA still believes that the decision not to include a Transitional Congestion Charge in the Proposed TPM is a lost opportunity to incorporate some flexibility into transmission charges in a no-regrets manner to manage an unquantified risk of a surge in peak demand…*

*This charge would have been designed to encourage actions to reduce peak demand on the network. That is, provide a financial incentive to take this action and avoid or defer new transmission investment for a transitional period.*

*It would seem prudent give the uncertainty of demand growth for decarbonisation to have something already in the 'toolkit' to ensure reliable supply and avoid constraints."*

2.5.5. Vector submission said:[28]

*"We consider removing the RCPD charge without a replacement equivalent price signal at peaks will remove a significant lever for incentivising the uptake of peak shifting technologies and flexibility services such as load control which would ultimately reduce the need for expensive grid upgrades.*

[24] NZ Steel sub, page 6

[25] Oji Fibre sub page 2

[26] Oji Fibre sub page 2

[27] IEGA sub page 5-6 (footnotes omitted)

[28] Vector sub, page 3 (footnotes omitted)

*We note Transpower's analysis suggests that removing the RCPD would lead to a potential demand increase of 303 MW. This is a significant increase and underscores the benefit the RCPD charge for the HVAC grid has delivered in terms of avoiding future investment.*

*For Vector, minimising the RCPD charge for our customers has been the dominant reason to control load during peak demand periods. With the removal of the RCPD charge, Vector will pursue other opportunities for its load control which will likely preclude us from load controlling during peak times. The new TPM therefore appears to have muted a key driver for peak demand management and encouraging flexibility services which are important attributes in an electrifying economy.*

2.5.6. Vector agrees with our view that the events of 9 August demonstrate the importance of peak shifting for the security of New Zealand's energy system:[29]

*"We are unclear how the Authority reconciles its decision to remove the peak price signal with the findings of the Hodgson review. Rather than encourage demand side participation, the Authority instead risks putting a nail in the coffin for ripple control investment and maintenance."*

2.5.7. Northpower and Top Energy explain in their joint submission why they think that Transpower has underestimated the costs of removing the RCPD price signal in their regions. They think that peak demand could increase by 10% or about 700MW on the grid.

2.5.8. Northpower and Top Energy are concerned that nodal price signals will not achieve the same effect as the RCPD charge:[30]

*"While we understand the theory that 'nodal pricing sends a price signal' to control load on cold winter nights because of high spot prices, in reality it doesn't work because neither networks nor consumers receive this price signal. Retailers receive this signal, and while we have engaged with them as to whether they want us to load control to manage their generation costs, we received little interest. This is complicated by the fact that ripple control is not configured, or easily configurable, to control or not control based on who the retailer for the ICP is.*

*Consumers for the most part do not receive spot price signals to manage their load, nor do they have the automated ability to do so. As such, increases in load will drive spot prices higher, and retailers will respond by increasing their (for the most part non-cost reflective) price signals across the board rather than using a targeted price signal to incentivise consumers to avoid peak times.*

*We do agree that distributors will continue to use ripple control to manage their own network peaks, but this is limited to the actual timeframes that distributors have congestion. Currently we expect to employ load control very rarely outside of managing planned or unplanned outages, and we caution Transpower not to over-estimate the amount that networks will need to use load control to manage their own congestion.*

*For example, during the grid emergency event on 9 August 2021, Northpower did not have any congestion on its network which required control, and we foresee little requirement to control demand in the near future for the purposes of managing our network. While Top Energy did experience some isolated congestion e.g. Taipa substation, future upgrades mean we also see little requirement to control demand in the future for the purposes of managing our network.*

*As such, we are concerned as to whether generators and Transpower have the capacity to respond to a 700MW increase in peak load, and whether they can do so without frequently resorting to emergency measures and requiring curtailment."*

2.5.9. Hiringa Energy's submission records the need to "*shift consumption away from peak demand periods is more crucial now than ever*". It also agrees with our view that the Authority is placing too much faith in the ability of "*wholesale prices and emerging technologies, real-time pricing and new business models to signal congestion and real time response*" at the present time.

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[29] Vector sub, page 4

[30] Northpower and Top Energy sub, page 4

2.5.10. Hiringa Energy's submission explains how, under the existing RCPD charge and wholesale electricity pricing, it is able to value the flexibility of these assets and provide demand response to the wholesale market and congestion management during peak consumption periods. In contrast:[31]

> *"Under the proposed TPM changes Hiringa would be incentivised to take our electrolysers off the grid, where a 'behind the meter' solution using a combination of renewable generation, storage and flexible demand services can achieve a lower delivered cost of electricity than can be achieved from the grid. While Hiringa can only speak for our business cases, this would suggest that other emerging technologies and new business models will be incentivised, under the proposed TPM changes, to do the same. The cost of these solutions going off the grid is a missed opportunity which will ultimately result in less demand response and higher costs for the remaining customers connected to the grid."*

# 3. DESIGN CHOICES

## 3.1. Pooling and sharing for FMD Type 2

3.1.1. Stakeholders are concerned about the Authority's proposal to apply a BB type method for anticipatory connection investments.

3.1.2. Contact Energy believes these investments should be funded by the Government either directly or via lower returns. Failing this, its preference is for the pooling and sharing approach:[32]

> *"The principal reason for our preference for pooling and sharing relates to its simplicity. We see the alternative benefit-based options as being overly complex and therefore unlikely to elicit the stakeholder interrogation of anticipatory investments that the Authority assumes".*

3.1.3. Fonterra also supports an approach which is easy to understand and implement:[33]

> *"Fonterra's preferred approach is to pool and share the costs relating to anticipatory investments This appears to be a workable solution that could be relatively easily implemented."*

3.1.4. The Northpower and Top Energy submission comments that the real beneficiaries of anticipatory assets, i.e., future users should pay when they connect or alternatively these costs should either be:[34]

1) Absorbed by Transpower through a lower return on its RAB; or

2) Spread across all transmission customers as proposed by Transpower"

*3.1.5.* Transpower agrees with our view that the pool and share option is unlikely to trigger inefficient investment. It points out that the connection assets will be subject to scrutiny by the Commerce Commission whether they constitute base or major capex proposals.[35]

*3.1.6.* In relation to the Authority proposed BB approach Transpower notes:[36]

> *"In places, the choice comes down to socialising the cost across a subset of customers that have been selected on the basis of necessarily poor information, or socialising the cost across all customers. In our view the latter is more efficient….*

[31] Hiringa Energy sub, page 3

[32] Contact Energy sub, page 8

[33] Fonterra sub, page 2

[34] Northpower and Top Energy sub, page 3

[35] Transpower submission, page 16

[36] Transpower sub, pages 16-7 do we quote EA's paper

*Under the Authority's proposal the subset of customers that would be charged for the anticipatory capacity:*

- *may not necessarily be the expected majority or principal beneficiaries of the anticipatory capacity; and/or*
- *may not necessarily be expected to benefit from the anticipatory capacity (they could incur net disbenefits).*

*The subset of customers would simply be charged because they are there first. "*

3.1.7. This cannot lead to a durable outcome.

## 3.2. Weighting of benefits under the simple method

3.2.1. A number of stakeholders have pointed out that the Authority's design choice for the weighting of benefits between load and generation does not align with the evidence.

3.2.2. Contact Energy tested Method 1 using Transpower's estimates for adjusted operating profit for generators (as a proxy for the net private benefits of generators) and a range of consumer surplus estimates using the ratio of consumer to generator net benefits in Table B.5 of the Authority's 24 May 2021 letter to Transpower. All of the results show an implied generator weighting of much less than 50%, with 21% the base case. It concluded:[37]

> *"…our analysis suggests that the relative net private benefits of low-value investments between load and generators warrants an allocation of benefit-based charges under the simple method much closer to a 75:25 basis than the 50:50 basis proposed."*

3.2.3. Mercury submitted:[38]

> *"The cost and benefit analysis scenario which assumes a weighting factor of 75% to load and 25% to generation from the outset indicates materially higher net benefits than a scenario in which the weighting remains at 50:50 over the full 28 years being assessed ($2.4b vs $1.25b). Given there will be a review in five years Mercury considers it is better to have a 75/25 split from the outset to realise these benefits and avoid deterring investment in generation."*

3.2.4. Meridian Energy said:[39]

> *"Costs should be passed through in the most efficient way. As part of our submission on the 2019 issues paper, we included analysis from NERA demonstrating that since consumers ultimately pay for all transmission costs, it is more efficient and direct to assign costs to load customers. This is because the demand-side of the electricity market is more inelastic than the supply-side."*

Nova Energy refers to the Authority's analysis and says is surprised that the 50:50 split "*is even being considered*"[40]. Its submission explains why load and generators do not have the same benefit in the reliability and security and supply of the grid. In relation to its own peaking plant Nova Energy notes:

> *"a single circuit or N reliability Grid connection provides adequate security for the generator to inject electricity produced into the Grid. For example, both the McKee and Junction Road peaking facilities are constructed on the basis of a simple T-connection to a single Grid transmission circuit. The generation revenue lost from not being dispatched on the occasions that the circuit is disconnected did not justify the material additional capital investment required in building a full N-1 reliability connection, particularly as the plant is only expected to run around 30% of the time over the long run."*

[37] Contact Energy sub, page 2

[38] Mercury sub, page 2

[39] Meridian sub, page 2

[40] Nove Energy sub, page 5

3.2.5. Orion said:[41]

> *"The 50:50 weighting between load and generation appears arbitrary, and the ability to change it creates uncertainty (mainly for those considering generation investments). All costs ship home to consumers, one way or another, and we would like to see more work done on which route provides more efficient outcomes. If we can show that applying charges to load customers only provides efficient outcomes, then all charges should be applied to load customers (and vice versa)."*

3.2.6. However, there is support for the Authority's view from Fonterra[42] and Vector[43].

## 3.3. The design of the residual charge

3.3.1. A number of submitters are concerned about the design of the residual charge.

### *AMD assessed at each GXP*

3.3.2. The submission from the Major Electricity Users Group highlights the inconsistency experienced at the end of the Glenbrook connection line where the AMD which applies to NZ Steel is the sum of the AMD at each of two GXPs rather than the sum of coincident demands:[44]

> *"MEUG has concerns at the inconsistency of how the AMD allocator for setting initial residual charges for the 2 GXP supplying NZ Steel do not consider coincident demand whereas an equivalent load embedded in a distribution network would have the benefit of diversity downstream of the GXP. It seems there is one rule for grid connected end consumers with multiple GXP where there are multiple points of connection versus end consumers embedded in distribution networks with multiple ICP's."*

3.3.3. NZ Steel's submission also addresses this matter and refers to "*the total lack of logic and justification for using non-coincident demand for a customer when the GXPs are at the same location*." [45] In its view:[46]

> "*Continued insistence in the TPM proposal on using a non-coincidental peak demand at a single location reinforces the view that historic anytime AMD at the Customer level is a purely arbitrary allocator and undermines credibility and durability of the TPM proposals."*

3.3.4. Oji Fibre agree and state[47]

> *"Our strong view is that the calculation methodology for complex sites connecting to a single substation should be on the basis of coincident peak demand for the GXPs at that site. Continued insistence on using a non-coincidental peak demand at a single location reinforces the view that historic anytime AMD at the Customer level is a purely arbitrary allocator and undermines credibility and durability of the TPM proposals."*

### *Choice of gross vs net load*

3.3.5. The choice of a net load allocator for the BB charge and the gross load allocator for the residual charge continues to be criticised by submitters.

3.3.6. The IEGA submission says:[48]

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[41] Orion sub, page 7

[42] Fonterra sub, page 3

[43] Vector sub, page 6

[44] MEUG sub, page 3

[45] NZ Steel sub, page 4

[46] Ibid

[47] Oji Fibre, page 4

[48] IEGA sub, page 3

*"It is unclear how a different approach as proposed can be justified for the two transmission charges, especially as the Proposed TPM Residual Charge involves paying for transmission services that are not used. Further, the proposed approach for batteries is 'final consumption' which is the same as net load (or load minus generation) not total consumption as for Residual Charges to load customers."*

Orion's submission notes the inequity of charging for embedded electricity (embedded generation injected into a distributor's network) as if it was delivered by Transpower when it is not. It observes:[49]

*"This approach conflicts with the distribution pricing practice note which promotes locational pricing, where assets that serve a customer are identified to avoid cross-subsidies. The proposed TPM approach applies residual asset based charges to customers who are not using the assets.*

*The proposed approach is analogous to us asking a consumer if they use an alternative fuel source for heating, firewood for example, and then calculating an equivalent kWh and charging as if we had delivered that energy. In this respect, we do not think the approach is reasonable."*

Orion advise that the consequences of this discriminatory treatment are already occurring and further encouraging inefficient investment behind the meter.

3.3.7. Nova Energy are also concerned about the choice of gross load for the residual charge particularly in respect to co-generation:[50]

*"By grossing up for "load" directly supplied by a co-generation plant to its industrial customer, the draft TPM proposes to impose charges for services that will never be rendered by the Grid. The "load" can only exist when the co-generation plant is producing steam. If the co-generation plant is not operating (i.e. producing steam and electricity) the load will not exist because of the independencies of the steam and electricity use within the customer's industrial manufacturing process.:*

3.3.8. Oji Fibre is also concerned by the effect of the Authority's decision to calculate AMD on the gross rather than net load of cogeneration.[51] NZ Steel has a similar view.[52]

### *Implementation issues with the battery proposal*

3.3.9. Orion point out that there are practical issues associated with the Authority's proposed special treatment of batteries:[53]

*"Distributors (and the reconciliation system) only have visibility of the energy that flows to and from an end consumer's installation. When a consumer is injecting to our network, there is no way we can know if that injection is from generation, from the battery, or from a combination of the two. Further, even where injection is from the battery, we will not know if that battery was previously charged from the grid or from generation, or from a combination of the two.*

*The situation is further complicated when there is a combination of generation, batteries and load all behind a single meter. We understand that several grid scale solar projects include load (such as data centres) or are being located adjacent to existing load to take advantage of direct connection to that load.*

*We don't think it is feasible, practical, or efficient to require customers to measure energy that flows in and out of their batteries, measure energy from generation, and measure load within their installation and provide this to the industry. Given this limitation, the measurements identified in the examples in the Consultation Paper will not be available, and the calculations*

[49] Orion sub, page 2 (footnotes omitted)

[50] Nova Energy sub, page 1

[51] Ibid page 7

[52] NZ Steel sub, page 3

[53] Orion sub, page 3

*cannot be carried out. It does not appear that the Authority will be able to implement its objective for the vast majority of battery installations."*

3.3.10. It further notes that the root cause of this issue is the decision to use "gross load" in the allocation of the residual charge.

## 3.4. Concept of trailing exit charges

3.4.1. Some stakeholders continue to be troubled about the notion that the industry would seek to continue to apply transmission charges after plant closure and exit.

3.4.2. Contact Energy said:[54]

> *"Once a large plant has closed it is no longer drawing electricity from the grid and the transmission customer should not, in our view, continue to be liable for the benefit-based charges for benefit-based investments commissioned within the last 10-years. The argument put forward by the Authority to justify this policy position is that a transmission customer may have an incentive to close a large plant to avoid transmission charges. We consider this argument absurd given the magnitude of any decision to close a large plant, both in terms of personnel affected and remediation costs incurred. Similar arguments apply to large deratings of plant, or the closure or large derating of embedded generation".*

## 3.5. Proposed standalone prudent discount

3.5.1. In our primary submission we noted that the proposed standalone prudent discount is simply a discretionary discount which will be available to some customers but not others depending on what scenarios are assumed to apply when assessing stand -alone costs of hypothetical investments.

3.5.2. We agree with Vector's submission that:[55]

> *"The PDP appears to have been designed specifically for New Zealand Aluminium Smelters (NZAS) and allows them to apply for a prudent discount based on the estimated costs of building a proprietary transmission line from Tiwai Point to Manapouri (despite the fact such a project almost certainly would not obtain the required resource consent so could not actually be undertaken)."*

3.5.3. This is a worrying precedent for future Code changes.

3.5.4. We also note that the beneficiary of this reform believes the Authority should have given it more concessions including an extension of the discount to connection charges; costing based on used rather than new assets; and cost-free access to existing corridors and easements.[56]

3.5.5. We do not support these suggestions.

# 4. REGULATORY IMPACT ANALYSIS

4.1.1. No other submitter sought an independent review of the Authority's new CBA.

4.1.2. It is possible that submitters are not aware of the scale of the changes the Authority made from the 2020 CBA the Authority relied on to support its adoption of the TPM Guidelines.

4.1.3. However, Mercury said:[57]

[54] Contact Energy sub, page 2

[55] Vector sub, page 4

[56] Rio Tinto submission pages 8-9

[57] Mercury sub, page 3

*"Overall, Mercury considers that the cost and benefit analysis overstates the benefits and understates the costs. As we have highlighted above, the proposed TPM comes with significant compliance costs and durability concerns. It will not be easy for parties to come to grips with how their transmission costs are calculated. Mercury is concerned that efficiencies ascribed to "reduced uncertainty for investors" will more likely than not be negative in the short to medium term.*

*We do not agree with the Authority's assessment that with high expected demand growth, there are material gains from ensuring that investors consider the implications of investing in areas where they could exacerbate transmission capacity constraints. All investors have this consideration top of mind currently regardless of the TPM as transmission capacity constraints have a significant impact on whether a project is economic. We consider that Table 18 on investment efficiencies significantly overstates the benefits of the new TPM being proposed."*

## 5. Concluding remarks

Network Waitaki note that that "*in essence [this TPM] is reallocating the burden of cost recovery to different users*".[58] We agree and find the benefits that the Authority is claiming it will achieve from this reallocation exercise extraordinary.

Nevertheless, a review of submissions suggests that parties are already preparing for its implementation. For two groups in particular: those looking to invest in new generation or large industrial plant (embedded and directly connected) this TPM is not good news.

It will increase costs, not necessarily even-handedly, and make estimation of future transmission costs exceptionally difficult. Problematically the investment and operation decisions of this group are very important to the government's aspiration for the sector.

The big question is how long will this TPM survive, and will consumers see any benefits from it?

For any questions relating to the material in this submission, please contact Fiona Wiseman, Senior Advisor Strategy and Regulation on 027 5499330.

Regards,

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[58] Network Waitaki sub, page 1