Pioneer energy

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24 February 2017

Submissions
Electricity Authority
P O Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Carl,

RE: Transmission Pricing Methodology: Second issues paper: Supplementary consultation

Pioneer Energy (Pioneer) appreciates the opportunity to make this submission on the Electricity Authority's (Authority) Supplementary consultation paper.

Pioneer agrees that the Transmission Pricing Methodology Guidelines should provide Transpower with some flexibility to determine a practicable, implementable and durable method for recovering transmission costs. We support the draft guidelines published with the supplementary consultation paper which provide Transpower with discretion in designing and administering the TPM. In particular we agree with the:

i. discretion that Transpower has to determine the allocator for the residual charge;
ii. principles based approach for calculating the residual charge;
iii. opportunity for Transpower to include a long-run marginal cost charge.

However, we have concerns about the implementation of the proposed price cap, the criteria and application of Adjusted AMDs, and the modelling of the indicative charges. We elaborate on these aspects of the draft Guidelines below.

Pioneer also notes that the Authority's supplementary consultation has not yet adequately addressed or discussed other points made by Pioneer, and others, in previous submissions relating to overall system efficiencies and the proposed reliance only on nodal pricing signals for system demand response. Appendix 2 discusses these particular points.

Pioneer is a member of the Independent Electricity Generators Association (IEGA) and supports the IEGA submission.

i. Discretion to determine the allocator for the residual

We note that the Authority has stated that[1] the new distributed generation capacity in the Top Energy network is the same as a permanent reduction in demand resulting in a reduction in "Top Energy's reliance on the transmission grid". Pioneer has always believed that distributed generation is negative load and has recommended in many submissions that distributed generation be treated the same as load control or other methods of reducing demand.

Pioneer is concerned to ensure that any 'adjustments' to Anytime Maximum Demand allocators (or any other allocator) are applied consistently – no matter whether the provider of this service is a transmission customer or not. The Authority's modification of Top Energy's AMD, to include a new 25MW embedded generation project in the Northland region, as well as including demand response for selected consumers clearly results in the avoidance of transmission costs for these transmission customers.

This change is however arbitrary and conflicts directly with the economic inefficiency arguments the Authority created to remove ACOT benefits in its DGPP Decision paper – 6th December 2016.

Pioneer submits that when Transpower is determining the GXP level allocators there must be a transparent criteria and process applied for making any 'adjustments' to ensure there is equal treatment for equivalent customers or services, across all networks meeting that same criteria.

ii. Principles based approach for calculating the Residual charge

The 'principles' listed in clause 32 of the proposed Guidelines require that the Residual charge is designed so that any Distributed Generator is not paid for any transmission charge avoided by the relevant Distributor. We query if this clause is relevant, when the new DGPP Code now applies a Grid Reliability Test to approve existing payments by Distributors to Distributed Generation.

These Guidelines relate to transmission charges and have no direct influence over how a Distributor passes through transmission charges to its customers. We believe there should be some further thought and guidance as to how the Residual charge is reconciled with future payments from Transpower to new DG providers, with Adjusted AMD's and with DGPP payments made by Network businesses, either to 3rd party service providers or to themselves as owners of DG or battery storage.

The criteria applied relating to these principles needs to ensure a level playing field between competing services providers. For example, does this principle apply to all forms of generation installed within a distributor's network, including residential solar PV and batteries? Under the current structure of distribution pricing a residential consumer will also be 'avoiding' transmission charges by reducing the volumes it draws off the distribution and transmission network. We therefore suggest that a definition of 'Distributed Generation' is relevant for this clause.

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[1] See Letter from Electricity Authority to Pioneer Energy in Appendix 1 of this submission, page 4

iii. Long-run marginal cost (LRMC) charge

Peak demand drives the need for infrastructure investment (both transmission and distribution investment). Pioneer does not agree with the Authority's reliance on the nodal energy spot price to manage peak demand on inter-connection assets. While nodal spot prices are designed to include the impact of transmission constraints on a half hour by half hour basis, there is clear empirical evidence that average and seasonal nodal spot prices do not signal new investment for peak demand management.

We have provided information in letters and other submissions to the Authority that clearly shows nodal spot prices peak in autumn when demand peaks in winter / spring. There is also clear empirical evidence that GXP AMD level signals are not coincident and that a regional coincident LRMC signal is more appropriate for interconnection assets. Regional LRMC charges can be designed to provide a price signal that is sensitive to developing or changing peak demand constraints on the network.

The proposed AoB price signal is comparatively weak and only allocates the cost of investments once the investments have been made and the Residual is a postage stamp charge. In our view, these charges will not mitigate the level of peak demand on the networks. A well designed LRMC charge will provide a better and more efficient signal over an extended period of time, prior to the need for new transmission investment, than a consistently high spot price. The LRMC signal would be complimentary to a grid support contract and demand response programme which are more tactical and more aligned with System Operator, rather than Grid Owner, responsibilities.

Pioneer strongly supports the inclusion of a transparent, durable and economically efficient regionally based long-run marginal cost (LRMC) charge in the new TPM. An LRMC charge would provide an important signal to transmission customers and providers of services to manage peak demand, about the location of developing transmission constraints or the upcoming need for new transmission investments identified in Transpower's established long term transmission planning processes.

iv. Proposed price cap

Pioneer has not attempted to model how the proposed price cap will be implemented using the proposed Guidelines. We are concerned that the proposal requires Transpower to collect all the information about price changes proposed by all other participants involved in determining every other component of a customer's electricity bill and apply a transmission charge that is essentially the balancing item to ensure total charges increase by only 3.5% per annum. Any cap on transmission charges for one customer will increase charges for other customers – this is a wealth transfer between electricity consumers.

Is this cap economically efficient? Further, this change is likely to be compromised in its execution through the considerable vagaries of transmission and network pricing pass-through to Retailers and conflicts with competitive energy market pricing principles.

v. Modelling of indicative only charges and measures

While the Authority has modelled future transmission charges using the proposed methodology the results are 'indicative' only. These modelling changes do, however, reveal that the charges are incredibly sensitive to small changes in assumptions and therefore cannot be relied on at this time for planning any future investment in generation or load. These investments involve long planning lead times and are also being relied upon to deliver 'efficient' investment in and operation of the electricity industry.

Pioneer would prefer simpler and more predictable regional AoB and LRMC allocators, at the interconnection not the GXP level, which could be relied upon by small investors and not subject to modification each time a new Generation or Load connection is made. Transpower's[2] submission on the 2nd Issues Paper provided estimates of the inefficiency of the current pricing methodology, noting;

> *"While we recognise that there are equity concerns and the price signals provided by the RCPD and HVDC charges may be too strong we consider the inefficiency to be relatively small. For example, compared to a hypothetically perfectly efficient TPM, as assumed by Oakley Greenwood for the Authority, the level of inefficiency associated with the current TPM equates to 2.5% of revenue for the TPM as a whole (and 0.77% for the HVDC). We were, consequently, surprised by the Authority's statement that the TPM is "fundamentally inconsistent with the principles of efficient pricing."*

We re-iterate our 2nd Issues views that Transpower could achieve the same or better economic efficiency gains by tweaking the existing TPM, with far less complexity and market disruption than is envisaged by this new TPM Guideline. If the Guidelines are to be changed Pioneer supports adopting Transpower's proposed simplified transmission pricing methodology and staged approach (detailed in their submission on the 2nd Issues Paper).

We also note that the current TPM proposal and the analysis undertaken have no measurable objectives, efficiency targets, or KPI's for this relatively complex and potentially disruptive change in pricing practices. Pioneer requests that the Authority agrees with Transpower, and then reports against a set of *specific and agreed efficiency outcomes* supporting long term consumer benefits as reflected in their final CBA outcomes.

Yours sincerely

Fraser Jonker
Chief Executive

Appendix 1: Correspondence between Pioneer Energy and the Electricity Authority
Appendix 2: Issues raised by Pioneer that are as yet unresolved

[2] Transpower 2nd Issues Submission – ref; Section 2.1.1, Page 23.

Appendix 1: Q&A correspondence between Pioneer Energy and the Electricity Authority

1. Letter and request for further information from Pioneer Energy, 23 December 2016
2. Response from Authority, 30 January 2017
3. Letter and request for further clarification from Pioneer Energy, 17 January 2017
4. Response from Authority, 15 February 2017

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23 December 2016

Carl Hansen
CEO
Electricity Authority
P O Box 10041
Wellington 6143

By email: carl.hansen@ea.govt.nz

Dear Carl,

RE: Clarification of DGPP Cost-Benefit, Reliability Standard and TPM Overlaps

Thank you for the follow up meeting with yourself, Brent Layton and your wider team to discuss your final DGPP decision report. This letter seeks further clarification on the cost-benefit analysis supporting your DGPP decision and the relationship between the DGPP decisions and the ongoing Transmission Pricing Methodology (TPM) consultation process.

Pioneer raised a number of energy market related pricing impacts in both its DGPP and TPM submissions that we believe impact the cost-benefit analysis (CBA) for both proposals. It is clear from reading your DGPP decision report that these matters were investigated by advisors Concept Consulting, but then appear to have not been addressed in the CBA analysis supporting your statutory requirements. We highlight the relevant sections from the DGPP decision report are as follows:

Pioneer Submission Reference	DGPP Report Reference	Modelled Pricing Impacts to Consumers
Clause 2.13, reference Fig. 2 on page 9; "Parts 3 & 4 are direct benefits to consumers. Pioneers TPM submission provides indicative analysis covering how these marginal pricing and avoided losses benefits, estimated at more than $500m per annum, are realised. DG providers currently receive no payment consideration for these benefits, which equate to an estimated $16/MWh benefit to all consumers."	No reference made to energy market costs or efficiencies in the EA Review Report except through Appendix D; Concept Analysis Base Case assumptions; • 117MW reduced DG peak demand response. • 50MW reduction of Industrial demand response • 50MW reduction from commercial/smaller users • 170MW reduction of Ripple control capacity • Net 50MW reduction of ripple after assuming 120MW of ripple control shifts to reserves market, freeing up 100MW of generation for supply. Overall, Base Case assumes 270MW of lost winter peak demand response, which is a reduction of around 20% of the current ACOT peak demand response. Energy costs to consumers are calculated by Concept at more than $50m per annum, against the DGPP cost-benefits calculated at Present Value Base Case = PV32.7m *Concept notes in 5.3 this issue may warrant further consideration to determine scale and likelihood of impact.*	Authority DGPP Cost-Benefit Analysis base case shifts from Concept Report - Section 5 Indicative impacts on market prices. *5.1 No sustained effect on prices expected.* • Findings ignore the consumer costs of paying *5.2 Potential Transitional Scenario.* Concept calculates the modelled market pricing impact was a marginal spot price increase over the 100 peak hours of $100/MWh, or a time weighted nodal price over the year of $1.5/MWh. *5.3 Effect of price uncertainty* Confirms Pioneers question of additional energy costs increases to consumers of more than the current ACOT payments to DG.

Consumer energy cost impacts calculated by Concept exceed the range of cost-benefits attributable by the Authority to the changes being made to the DGPP Code.

Pioneer therefore believes that the DGPP decision does not meet the Authority's statutory objectives and would like a formal response on this particular decision anomaly.

Transpower Grid Reliability Standard Review

Our reading of the DGPP Decision Report is that the Authority has ruled Competition and Efficiency benefits do not warrant ACOT payments, but that DG could avoid transmission costs required to ensure Reliability under the Code.

Given the Code amendments require that Transpower undertake a Reliability review for each transmission region in New Zealand, our understanding is the current status of the DGPP consultation and decision making process will not be completed until the Authority approves Transpower recommendations for each Region e.g. for the Lower South Island the process will not be completed until on or before 31st October 2017.

Can you confirm please our interpretation of the decision process timelines to meet all of the Authority and Transpower statutory requirements?

TPM Decision Process Overlaps

We note from the recent supplementary information released in support of the Transmission Pricing Proposal the Authority has made a number of material changes to its Area of Benefit models and cost allocation calculations. We calculate these changes as having around $54m per annum of further wealth transfers between different Networks and Industry connected users, based on the original proposals outcomes.

This level of change, for what appear to be modest adjustments to the AOB model inputs, highlights to us the concerns we and others have raised in our TPM submissions as to the fraught nature of allocating private and public benefits for long term infrastructures on a "point-in-time" power flow analysis. We also have concerns as to the nature of these specific adjustments, as many of the connections where changes have been made appear to also have material Distributed Generation connections.

We would therefore like to satisfy ourselves that the TPM and AOB analysis is being applied consistent with your DGPP Code change decisions, which we assume are now precedent to any TPM decisions. In this regard, we request further empirical and modelling input details relating to our TPM consultation as follows:

1. All changes to the input assumptions for Generation as at the modelled 2019 forecasts for TPM, in particular assumptions relating to Authority references to "well signalled" generation investment or divestment decisions e.g. Ngawha extension, Nova Otarahonga Peakers, Huntly

decommissioning all of which are signalled outcomes for implementation by 2023.

2. Input assumption changes and/or calculations relating to any GXP Demand and Anytime Maximum Demand (AMD) calculations made between the prior and the latest issue of TPM cost allocations. In particular, those calculations relating to the material differences for Networks or Direct Connections served by Distributed Generation and Cogeneration plant.

Given the very short timeframe allowed for the next TPM submissions, we would appreciate the Authority responding with further information on these matters as early as possible in the New Year.

Yours truly

Fraser Jonker
CEO
Pioneer Energy

ELECTRICITY AUTHORITY
TE MANA HIKO

30 January 2017

Fraser Jonker
CEO
Pioneer Energy
PO Box 275
ALEXANDRA 9340

Dear Fraser

Clarification of DGPPs Cost-Benefit, Reliability Standard and TPM Overlaps

Thank you for your 23 December 2016 letter requesting clarification of the cost-benefit analysis for the Distributed Generation Pricing Principles (DGPPs) Code amendment decision and the relationship between the DGPP decision and the ongoing Transmission pricing methodology (TPM) consultation process.

Your letter asks for a response to the following three points, as described in your letter.

1. The consumer energy cost impacts calculated by Concept exceed the range of cost-benefits attributable by the Authority to the changes being made to the DGPP Code. Pioneer therefore believes that the DGPP decision does not meet the Authority's statutory objectives and would like a formal response on this particular decision anomaly.
2. The DGPP consultation and decision making process will not be completed until the Authority approves Transpower recommendations for each Region, eg for the Lower South Island the process will not be completed until on or before 31 October 2017. Can you confirm please our interpretation of the decision process timelines to meet all of the Authority and Transpower statutory requirements.
3. Further empirical and modelling input details relating to our TPM consultation as follows:
    a. All changes to the input assumptions for Generation as at the modelled 2019 forecasts for TPM, in particular assumptions relating to Authority references to "well signalled" generation investment or divestment decisions eg Ngawha extension, Nova Otarahonga Peakers, Huntly decommissioning all of which are signalled outcomes for implementation by 2023.
    b. Input assumption changes and/or calculations relating to any GXP Demand and Anytime Maximum Demand (AMD) calculations made between the prior and the latest issue of TPM cost allocations. In particular, those calculations relating to the material differences for Networks or Direct Connections served by Distributed Generation and Cogeneration plant.

Our responses are provided below.

Clarification of CBA

As I understand your position, you expect the DGPPs decision (in combination with the proposed changes to the transmission pricing methodology) to raise 'consumer energy cost impacts' by more than $50 million per annum. Your letter states that this impact exceeds the Authority's expected present value of net benefits of $32.7 million that will arise from its DGPPs

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decision and the size of avoided cost of transmission (ACOT) payments. Pioneer therefore concludes that the DGPPs decision is inconsistent with the Authority's statutory objective.

I do not consider that the assessment in your letter is economically robust because it focuses on wealth transfers rather than economic effects (ie, the effect of the DGPPs decision on resource costs, which ultimately flow to consumers). This leads to misleading apples and oranges comparisons and conclusions.

As an example, a key area where we believe Pioneer does not properly identify the economic effects is the wholesale electricity market. Your letter appears to suggest that ACOT payments would reduce marginal energy prices, due to the operation of distributed generation. This is treated as a benefit, even though price effects are largely wealth transfers between different parties in the first instance. The primary economic impact of price changes arises from altered resource decisions, such as different investment levels or fuel usage.

Further, it is not entirely clear how the "more than $50 million" figure has been calculated.

DGPP consultation and decision making process

The DGPPs decision amended the Electricity Industry Participation Code 2010 (Code) such that under the regulated terms distributors will make ACOT payments only to existing distributed generation that is required in order for Transpower to meet the Grid Reliability Standards in the Code. Contrary to the implication in your letter, this amendment promotes efficiency (by removing inefficient incentives on investment and operation of distributed generation) and enhances competition. This is clearly stated on page 25 of the decision paper.

The Code requires Transpower to provide the Authority with reports about which distributed generators in each of the four transmission regions are required for it to meet the Grid Reliability Standards. The timing for the reports is different for each of the regions. For the Lower South Island region, Transpower must provide the report by 15 March 2017 or such later date as the Authority may allow.

The Authority will then decide, based on Transpower's advice, which existing distributed generation in each region should receive ACOT payments under the regulated terms. As part of this decision process we intend to consult with affected parties before finalising a list of the distributed generation in each region that should receive ACOT payments.

No deadline has been set for the Authority to publish such a list.

I am unaware of the basis for your statement that "for the Lower South Island the process will not be completed until on or before 31st October 2017". The Code amendment came into force on 9 January 2017, although it will only have effect from 1 April 2018 for distributed generation located in the Lower South Island region. Transpower is required by the Code to provide the Authority with a report relating to distributed generation in the Lower South Island by 15 March 2017 (or such other date as the Authority may allow), and the Authority will at some time after this point publish a list of distributed generation for the Lower South Island region.

By the way, for future reference it is not correct to characterise the making of the report and the publishing of the list as part of the "DGPP consultation and decision-making process". There will be some decisions required by Transpower and the Authority to implement the Code amendment but that is normal as implementation usually involves some decisions.

Further empirical and modelling input details

We are preparing the further indicative modelling input details you requested. The intention is that this information will be provided separately, together with our response to Pioneer's letter of 17 January 2017, later this week or early next week. We will publish the information on our website. On this matter we note that, as clearly indicated in Appendix F (the modelling appendix), of the TPM supplementary consultation paper, the modelling is indicative only. The modelling necessarily makes a number of assumptions and simplifications. The Authority is currently proposing guidelines for a new TPM, not the TPM itself. And the guidelines can be interpreted and applied in a final TPM (if it changed) in different ways. For this reason the modelling is broadly indicative only.

Thank you again for your letter.

Yours sincerely

Carl Hansen

Carl Hansen

Pioneer energy

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17th January 2017

Carl Hansen
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P O Box 10041
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By email: carl.hansen@ea.govt.nz

Dear Carl,

RE: Clarification of "EA Results Analysis" TPM Allocation Methodology

Further to Pioneer Energy's letter dated 23 December 2016, in which we sought further clarification on the overlaps between the DGPP and TPM inter-dependencies and cost-benefit processes, the Authority has issued its "EA Results" analysis spreadsheets for the modified TPM. The minor changes applied have resulted in material cost allocation changes between participants.

This spreadsheet has various adjustments to the original 2nd Issues input assumptions, most related to Industrial Cogeneration GXP connections and their Load relationships to local Network GXP loads and connections. Our interpretation of the AMD calculations is they have been derived at each GXP from market reconciled ICP data, from NHH meters profiled and HH TOU actuals. They therefore represent the Gross Demand for each Grid Connection but do not yet account for peak Demand Response (DR). Are we to assume that you have decided to change the TPM allocation methodology so that Networks continue to be rewarded for the avoidance of transmission costs from demand response?

The Authority has advised a more principled and less prescriptive approach is to be applied. However, modifications described in the latest TPM paper to AMD's for Industrial Cogeneration appear to conflict with your new DGPP Code process for the determination of avoided transmission costs by Transpower. These modifications appear to grandfather avoided transmission charges for selected DG providers, DR and some Networks at the expense of others. This potentially creates competition issues between Networks that currently own embedded generation, Joint Venture businesses owning cogeneration and all other independent DG providers.

On the one hand, you are allowing large Direct Connect and some Network customers to benefit from existing DG + DR + Future DG investments, thereby avoiding charges for transmission that is already built, yet in your DGPP decision you have explicitly removed that same opportunity from smaller DG providers and from consumers that have invested historically to avoid transmission costs. (i.e. the Authority has now moved on to picking its own winners and losers). This change contradicts your DGPP arguments that investing to avoid transmission costs and charges is inefficient and your statutory objectives as represented in the DGPP decisions.

To ensure we have not misunderstood this analysis, we are seeking further clarification on the modelling assumptions used relating to avoided charges versus avoided costs of transmission;

a. Why has the Authority elected to grandfather avoided transmission charges for selected Direct Connected and Network participants through the modified TPM, without those parties also being required to pass the same Reliability Standards Test as competing providers of DG and DR services are required to under the new DGPP Code?

b. Why has the Authority merged or "notionally embedded" various Network and Industrial GXP's in its vSPD assumptions, when the reconciled and metering data of all existing AMD's should be readily available?

c. How will you reconcile these ACOT anomalies with the Networks that also have DG related companies, and whom will secure an ACOT benefit through the modified AMD allocator?

d. Why has the Authority included a further 25MW of new DG capacity into its Northland vSPD input assumptions (surely in conflict with its recent stated DGPP principles) yet ignored all other well signalled new generation and new consented sites, including the Huntly exit (Schedule 1 attached), that could also be built within the same timeframe. What allocation principles are Transpower being asked to apply, when you can make such arbitrary forecasts?

e. Historic AMD's cannot be "double-counted" as they are all derived from reconciled ICP data so they must be additive. Why has the Authority included a -25MW reduction in the Orion Network AMD (at GXP CLH011), without making a +25MW offset charge at another node to equate total regional AMD's, as this is specifically required under the new proposal principles when a Load relocates?

f. Why is the Authority's AMD input at Clyde GXP double the value referenced in Transpower's GRR Report Max Demand forecasts for 2019? How will the Authority and Transpower assure DG owners that the Reliability Standards test will be applied using consistent assumptions to the TPM allocations?

We would appreciate your teams' responses to these and our prior letter of 23rd December questions so that we can ensure our TPM submission accurately reflects the intent reflected in changes to inputs noted and modelled outcomes. We would be happy to discuss these queries further with your team directly if suits.

Yours sincerely

Fraser Jonker
CEO

Encl.
Schedule 1 – Consented and Well Signalled Generation Options

Schedule 1 – Consented and Well Signalled Generation Options

Projects currently under construction, received consent or applied for consent

October 2016

Generation type	Region	ransmission Regio	Location / Name of Projec	Owned by	Capacity (MW)	Earliest commission date	Status	Notes
	Taranaki	LNI	Junction Road	Nova Energy	100	2016-2020	Consented	
Geothermal	Bay of Plenty	LNI	Te Ahi O Maui	Eastland Group	20	2018-2020	Consented	
	Bay of Plenty	LNI	Rotoma	Rotoma No. 1 Corporation	35	2017-2020	Applied for consent	
	Hawkes Bay	LNI	Ruataniwha Plains	Hawkes Bay Regional Inv Co	6.5	2017-2020	Consent under appeal	
	Hawkes Bay	LNI	Waitahora	Contact Energy			Consent lapsed	
	Hawkes Bay	LNI	Maungaharuru	Meridian Energy	270	2017-2020	Consented	
	Manawatu	LNI	Central Wind (Moawhango)	Meridian Energy	125	2017-2020	Consented	
	Manawatu	LNI	Turitea	Mighty River Power	303	2017-2020	Consented	
	Taranaki	LNI	Waverley	Trustpower	135	2017-2020	Applied for consent	
	Wellington	LNI	Castle Hill	Genesis Energy	860	2017-2020	Consented	
	Wellington	LNI	Puketoi	Mighty River Power	159	2017-2020	Consented	
	Wellington	LNI	Long Gully	Windflow Technologies	12.5	2017-2020	Consented	
Subtotal LNI					**2026**			
Hydro	Canterbury	LSI	Rakaia River	Ashburton Com. Water Trust	16	2017-2020	Consented	
	Canterbury	LSI	Lake Pukaki	Meridian Energy	35	2017-2020	Consented	
	Canterbury	LSI	North Bank Tunnel	Meridian Energy	240	2017-2020	Applied for consent	
	Canterbury	LSI	Balmoral Hydro	Meridian Energy	15	2017-2020	Applied for consent	
	Otago	LSI	Hawea Control Gate Retrofit	Contact Energy	17	2017-2020	Consented	
	Otago	LSI	Upper Fraser	Pioneer Generation	6.5	2020	Consented	
	Otago	LSI	Mahinerangi Stage 2	TrustPower	164	2017-2020	Consented	
	Southland	LSI	Kaiwera Downs	TrustPower	240	2017-2020	Consented	
Subtotals LSI					**733.5**			
Gas	Auckland	UNI	Otahuhu C	Contact Energy			Consented	Otahuhu plant is closed down
	Auckland	UNI	Rodney	Genesis Energy			Consented	Genesis Energy will not progress the project
	Waikato	UNI	Waikato Power Plant	Nova Energy	360	2021-2022	Applied for consent	
	Northland	UNI	Ngawha expansion	Top Energy	50	2017-2020	Consented	
	Waikato	UNI	Tauhara II	Contact Energy	250	2020	Consented	
Marine	Northland	UNI	Kaipara Harbour pilot	Crest Energy	200	2017-2020	Consented	
Wind	Auckland	UNI	Awhitu	TrustPower	18	2016-2020	Consented	
	Waikato	UNI	Hauāuru mā raki	Contact Energy			Consented	Contact Energy will not progress the project
	Waikato	UNI	Taharoa	Taharoa	54	2017-2020	Consented	
	Waikato	UNI	Taumatatorara	Ventus	44	2017-2020	Consented	
Subtotal UNI					**976**			
Diesel	Canterbury	USI	Bromley	Orion	11.5	2017-2020	Consented	
	Canterbury	USI	Belfast	Orion	11.5	2017-2020	Consented	
	Marlborough	USI	Wairau	TrustPower	70.5	2017-2020	Consented	
	West Coast	USI	Stockton Plateau	Hydro Developments Ltd.	25	2017-2020	Consented	
	West Coast	USI	Stockton Mine	Solid Energy	35	2017-2020	Consented	
	West Coast	USI	Arnold (Dobson)	TrustPower	46	2017-2020	Consented	
	Canterbury	USI	Mt Cass	MainPower	55	2017-2020	Consented	
	Canterbury	USI	Hurunui	Meridian Energy	76	2017-2020	Consented	
Subtotal USI					**330.5**			

ELECTRICITY AUTHORITY
TE MANA HIKO

15 February 2017

Mr Fraser Jonker
CEO
Pioneer Energy
11 Ellis Street, PO Box 275
ALEXANDRA 9340

Dear Mr Jonker

RE: Clarification of "EA Results Analysis" TPM Allocation Methodology

Thank you for your letter dated 17 January 2017 seeking clarification on the impact to Pioneer of the Authority's transmission pricing methodology (TPM) proposal outlined in the TPM second issues paper: supplementary consultation. We also thank you for your earlier letter dated 23 December 2016. You will note that the 23 December 2016 letter principally related to the Authority's distributed generation pricing principles (DGPP) decision and the Authority advised that it would respond separately to the TPM related questions in that letter.

Given the technical nature of some of the questions and responses, we have opted to set out our responses (in red) under your questions. The responses relate to both the 17 January 2017 letter and the TPM related questions from the 23 December 2016 letter.

Yours sincerely

Carl Hansen

Carl Hansen
Chief Executive

Authority response to Pioneer questions on 17 January 2017, also TPM related questions on 23 December 2016

Authority responses included in red below.

17 January 2017 letter

RE: Clarification of "EA Results Analysis" TPM Allocation Methodology

Further to Pioneer Energy's letter dated 23 December 2016, in which we sought further clarification on the overlaps between the DGPP and TPM inter-dependencies and cost-benefit processes, the Authority has issued its "EA Results" analysis spreadsheets for the modified TPM. The minor changes applied have resulted in material cost allocation changes between participants.

This spreadsheet has various adjustments to the original 2nd Issues input assumptions, most related to Industrial Cogeneration GXP connections and their Load relationships to local Network GXP loads and connections. Our interpretation of the AMD calculations is they have been derived at each GXP from market reconciled ICP data, from NHH meters profiled and HH TOU actuals. They therefore represent the Gross Demand for each Grid Connection but do not yet account for peak Demand Response (DR). Are we to assume that you have decided to change the TPM allocation methodology so that Networks continue to be rewarded for the avoidance of transmission costs from demand response?

The Authority has advised a more principled and less prescriptive approach is to be applied. However, modifications described in the latest TPM paper to AMD's for Industrial Cogeneration appear to conflict with your new DGPP Code process for the determination of avoided transmission costs by Transpower. These modifications appear to grandfather avoided transmission charges for selected DG providers, DR and some Networks at the expense of others. This potentially creates competition issues between Networks that currently own embedded generation, Joint Venture businesses owning cogeneration and all other independent DG providers.

On the one hand, you are allowing large Direct Connect and some Network customers to benefit from existing DG + DR + Future DG investments, thereby avoiding charges for transmission that is already built, yet in your DGPP decision you have explicitly removed that same opportunity from smaller DG providers and from consumers that have invested historically to avoid transmission costs. (i.e. the Authority has now moved on to picking its own winners and losers). This change contradicts your DGPP arguments that investing to avoid transmission costs and charges is inefficient and your statutory objectives as represented in the DGPP decisions.

To ensure we have not misunderstood this analysis, we are seeking further clarification on the modelling assumptions used relating to avoided charges versus avoided costs of transmission;

a. Why has the Authority elected to grandfather avoided transmission charges for selected Direct Connected and Network participants through the modified TPM, without those parties also being required to pass the same Reliability Standards Test as competing providers of DG and DR services are required to under the new DGPP Code?

   After considering submissions on the second issues paper, the Authority amended the draft guidelines to provide additional discretion to Transpower in its design of the TPM. The draft guidelines in the second issues paper required the residual charge allocator to be a proxy for physical capacity; being either transformer capacity, line capacity or gross anytime maximum demand (gross AMD). However, the draft guidelines in the supplementary consultation paper (draft guidelines) propose to allow Transpower the flexibility to develop the residual charge subject to certain criteria. Namely, the residual charge must (among other things):

- apply to load
- correct for double counting and other anomalies
- result in broadly equivalent charges for customers in broadly equivalent circumstances
- be difficult to avoid
- be related to the size of a customer's load.[1]

The proposed guidelines do not specify whether the residual charge must be anytime maximum demand (AMD) or, if it is, whether it should be net or gross. However, in order to calculate indicative charges, to assist parties to understand how the TPM might impact them, the Authority modelled the residual charge with gross AMD as the allocator.

It is important to note that Transpower may propose a different allocator, and that the modelled charges are indicative only. Actual charges under a revised TPM may differ significantly from those modelled. We emphasise that the Authority's TPM proposal is set out in the draft guidelines and not in the modelling. Assumptions that have been used for modelling purposes should not be read as implying an Authority position on particular aspects of TPM design. For those aspects not specified in detail in the guidelines, Transpower would have discretion to propose the approach that best met the requirements of the guidelines and the Code and best promoted the Authority's statutory objective.

As described in the Authority's response to the Pioneer letter dated 23 December 2016 (provided below), the modelling did include a number of amendments to parties' gross AMDs to reflect updated information provided to the Authority and to model similar parties on a more consistent basis. For example, direct connect co-generation was modelled on a consistent basis for all direct consumers, and on the same basis as previously, which was to net it off. However, note that the guidelines do not specify this treatment. Further, some anomalies were addressed. Also, Top Energy's gross AMD was reduced by 25MW to account for the 25MW Ngawha expansion which has been announced.

The reason the Authority decided to adjust its indicative charges to account for the possible impact of the Ngawha expansion is because parties in the Far North requested this information. The Authority recognises that other regions may be in a similar situation as the Far North as per your Schedule 1 (attached below).

The Authority's approach for adjusting Top Energy's gross AMD downwards by 25MW was developed after balancing the guiding principles for the residual charge provided in the draft guidelines. Specifically, the modelling reflects clause 32(e) that requires that the residual allocation must be related to the size of a customer's load. The Ngawha

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1 Draft TPM guidelines, supplementary consultation paper; Clauses 32(a), 32(b), 32(c), 32(d), respectively.

expansion would presumably reduce Top Energy's reliance on the transmission grid, ie, it would be a permanent change in demand.[2] The modelling of Ngawha's charges reflects paragraph 3.120 of the supplementary consultation paper, which discusses a possible approach for allocating residual charges, termed "adjusted AMD".

The approach means that, unless recent DG (ie, commissioned within the last 10 years) would have reduced actual transmission capacity requirements at a grid connection point, there is unlikely to be any material difference between adjusted AMD and gross AMD. The approach does, however, mean customers are not penalised because of material changes in demand etc that have happened or are forecast to happen on the basis of information prior to the release of the policy, provided they would reduce capacity requirements.

Note that clause 4(d) of the draft guidelines provides for competitive neutrality between grid-connected generation, distributed generation (DG), and demand response, to the extent practicable. The matter of practicability is a matter for Transpower to consider. To expand on the question of practicability, it may be necessary or efficient to apply thresholds. The extent of inclusion of small scale DG and DR in the calculation of charges is a matter for Transpower to consider when balancing the guiding principles for the residual charge.

b. Why has the Authority merged or "notionally embedded" various Network and Industrial GXP's in its vSPD assumptions, when the reconciled and metering data of all existing AMD's should be readily available?

   The Authority merged network and industrial GXP's to the extent that industrial GXP's are embedded, based on the information it had at the time the indicative modelling was prepared.

   In the Authority's modelling for the second issues paper, indicative transmission charges were modelled for some embedded large consumers, such as Oji Fibre, which is a customer of Powerco. The Authority provided separate charges for certain embedded large industrials to assist those parties to understand the potential implications of the Authority's proposal. In practice, the way transmission charges are passed on to such consumers is a matter for distributors and the particular customers.

   The modelling of the proposal in the supplementary consultation paper would not be robust in relation to the application of the cap if embedded customers were treated as though they were direct connect customers. This is because, for example, the proposed cap might bind on a direct connect customer but not for a similar industrial if they were connected to a distributor that was well below the cap. To address this issue, the Authority revised its modelling so that embedded industrials were not treated as direct connect customers. Thus, Oji Fibre's indicative charges were rolled up into Powerco's charges.

c. How will you reconcile these ACOT anomalies with the Networks that also have DG related companies, and whom will secure an ACOT benefit through the modified AMD allocator?

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2 Clause 22(c) of the Draft TPM guidelines provides discretion to Transpower to optimise assets where demand for an asset reduces by more than 20%.

As stated in the response to question a, this is a matter for Transpower to consider, should the Authority confirm the draft guidelines.

Clause 32(f) of the draft guidelines sets out the principle Transpower must follow with respect to payment of ACOT in design of the residual charge. This relates to all DG, irrespective of ownership. In particular, clause 32(f) states that the method for calculating the residual charge must:

> *"be designed so that any distributed generator that is paid or credited for transmission charges avoided by the relevant distributor would not receive such payment or credit in respect of the residual charge component of the relevant distributor's transmission charges (for example, by adding back a value representing the load supplied by the distributed generator for the purpose of calculating the residual charge)."*

The clause was included to clarify that if, under a revised TPM, distributed generation (DG) injection volumes would otherwise reduce a distributor's share of the residual charge (eg, if net AMD or a similar "net" allocator was applied for calculating residual charges) and this results in avoided cost of transmission (ACOT) payments or the equivalent, an approach to calculating the residual charge should be applied such that no ACOT payment would be made, eg, by subtracting the injection in calculation of the charge.

The residual charge recovers a fixed cost. Thus, if under a revised TPM, DG injection volumes reduced a party's share of the residual, this would not reduce transmission costs or the size of the residual, but would just shift the avoided charge onto other parties, which would not promote efficiency. Accordingly, the principles for the design of the residual charge are intended to counteract incentives for operation of DG to avoid it.

This is consistent with the Authority's distributed generation pricing principles (DGPPs) decision in which the Authority determined that ACOT payments should only continue to the extent that a DG efficiently defers or reduces grid costs, but not where transmission charges are simply shifted onto other parties.

d. Why has the Authority included a further 25MW of new DG capacity into its Northland vSPD input assumptions (surely in conflict with its recent stated DGPP principles) yet ignored all other well signalled new generation and new consented sites, including the Huntly exit (Schedule 1 attached), that could also be built within the same timeframe. What allocation principles are Transpower being asked to apply, when you can make such arbitrary forecasts?

   Refer response to question a.

   It is important to re-emphasise that the charges are indicative only and the approach taken in the modelling does not bind Transpower. Rather, as stated above, it is the TPM guidelines that set the requirements for TPM design.

e. Historic AMD's cannot be "double-counted" as they are all derived from reconciled ICP data so they must be additive. Why has the Authority included a -25MW reduction in the Orion Network AMD (at GXP CLH011), without making a +25MW offset charge at another node to equate total regional AMD's, as this is specifically required under the new proposal principles when a Load relocates?

The treatment of double counting will be a matter for Transpower to consider, should the Authority adopt the guidelines proposed in the supplementary consultation paper. However, refer to the following extract from Buller Electricity's submission on the second issues paper as an example of situation where aggregation may be appropriate:

> *"The Residual Charges published in the Second Issues Paper were allocated to BEL using the GXP AMD's listed in Table 1.*

Grid Exit Point (GXP)	*AMD (kW)*
ORO1101	*9,400*
ORO1102	*9,600*
WPT0111	*9,400*

Table 1 AMD used in Residual Charge allocation

> *While the half hour combined load at the ORO GXPs (ORO1101 + ORO102) is very similar to that at the WPT0111, the ORO GXPs were allocated a combined Residual Charge which was double that allocated to WPT0111. The reason why this occurred is because BEL takes supply at ORO at 110kV, as BEL owns its GXP Substation (Robertson St). With this transmission supply configuration, the electricity market requires that 2 GXPs are created (ORO1101 & ORO1102).*
>
> *During the normal course of events the load at the ORO GXPs will be fully transferred on to either ORO1101 or ORO1102 due to maintenance work or faults, resulting in the full AMD (or close to the full AMD) of the downstream load being registered on both GXPs. The end result is that BEL is charged double the Residual Charge for the ORO GXPs compared with the situation where the Robertson St Substation was Transpower owned, and BEL took supply at a single 33kV or 11kV GXP (as in the case of WPT0111).*
>
> *BEL is of the view that in the case of network configurations like the ORO GXPs, the AMD's at the GXPs should be aggregated (on a half hour basis) to determine a combined GXP AMD which is used to allocate the Residual Charge. Otherwise BEL would be heavily penalised for owning our own GXP Substation, and a level playing field would not exist between Transpower and Distributor owned GXP assets with respect to the Residual Charges incurred."* [end of submission quote]

Note, Orion's gross AMD is unchanged since the modelling for the second issues paper at 734MW.

f. Why is the Authority's AMD input at Clyde GXP double the value referenced in Transpower's GRR Report Max Demand forecasts for 2019? How will the Authority and Transpower assure DG owners that the Reliability Standards test will be applied using consistent assumptions to the TPM allocations?

Like all other GXPs, the AMD for Clyde GXP uses 2014 market data updated to a 2020 scenario. The assumptions used for this scenario are set out in Appendix B of the second issues paper. Please note this potential double counting issue in your submission on the supplementary consultation paper.

Regarding consistency of assumptions between the test (under Schedule 6.4 of the Code) used to determine which (if any) DG is required for Transpower to meet the Grid Reliability Standards (GRS) and TPM allocations:

- the assumptions used for the test under Schedule 6.4 will be developed by Transpower. Transpower has yet to identify the process it will follow in developing the test but there may be an opportunity for input from DG owners

- if the Authority decides to change the TPM guidelines, the parameters and any assumptions for determining charges under the TPM would be set out in the TPM itself. Should the Authority decide on new TPM guidelines, the Authority would expect Transpower to consult in the development of its proposal, and the Code requires consultation on the proposed TPM before the Authority makes a final decision on it.

We would appreciate your teams' responses to these and our prior letter of 23rd December questions so that we can ensure our TPM submission accurately reflects the intent reflected in changes to inputs noted and modelled outcomes. We would be happy to discuss these queries further with your team directly if suits.

<u>23 December 2016 letter (TPM related questions)</u>

TPM Decision Process Overlaps
We note from the recent supplementary information released in support of the Transmission Pricing Proposal the Authority has made a number of material changes to its Area of Benefit models and cost allocation calculations. We calculate these changes as having around $54m per annum of further wealth transfers between different Networks and Industry connected users, based on the original proposals outcomes.

This level of change, for what appear to be modest adjustments to the AOB model inputs, highlights to us the concerns we and others have raised in our TPM submissions as to the fraught nature of allocating private and public benefits for long term infrastructures on a "point-in-time" power flow analysis. We also have concerns as to the nature of these specific adjustments, as many of the connections where changes have been made appear to also have material Distributed Generation connections.

We would therefore like to satisfy ourselves that the TPM and AOB analysis is being applied consistent with your DGPP Code change decisions, which we assume are now precedent to any TPM decisions. In this regard, we request further empirical and modelling input details relating to our TPM consultation as follows:

1. All changes to the input assumptions for Generation as at the modelled 2019 forecasts for TPM, in particular assumptions relating to Authority references to "well signalled" generation investment or divestment decisions e.g. Ngawha extension, Nova Otarahonga Peakers, Huntly decommissioning all of which are signalled outcomes for implementation by 2023.

   The TPM supplementary consultation paper provides *incremental* modelling, in relation to two of the proposed refinements: addressing charging anomalies and the proposed cap. It does not provide a full reconsideration of the assumptions in the modelling in the 2nd issues paper, nor does it reconsider the calculation approach. The supplementary modelling was incremental so parties could assess the indicative incremental impacts of these particular proposed refinements against the modelling in the 2nd issues paper.

   It is important to emphasise that the modelling is indicative because the Authority is consulting on proposed TPM guidelines, and actual charges will depend on the TPM proposed by Transpower, should the Authority decide to adopt the draft guidelines. Actual charges could differ from the indicative modelling significantly. For example, Transpower may propose a different method for applying the area-of-benefit charge to the one that the Authority has used for modelling.

It is also important to emphasise that the assumptions used in the modelling *do not* reflect the DGPP Code change decisions, so the modelling assumes no changes to avoided cost of transmission (ACOT) payments, ie, the indicative charges assume ACOT payments continue at current levels. Accordingly, neither the inputs nor the results should be read as implying an Authority position on treatment of distributed generation given the DGPP Code changes. As set out in the Authority's Decisions and reasons paper on its Review of distributed generation pricing principles, Transpower will assess which distributed generators in each region are required for it to meet the Grid Reliability Standards, and advise the Authority of its findings. The Authority will decide, based on Transpower's advice, which existing distributed generation should receive ACOT payments under the regulated terms.

Regarding the changes to input assumptions, the North Island grid upgrade (NIGU) was remodelled for the purposes of calculating area-of-benefit charges, based on the following adjustments:

- 25MW of additional Ngawha generation which was reflected in vSPD modelling by removing demand from Kaikohe for each half hour period.
- the inclusion of Pacific Steel's charges into NZ Steel's charges, and the de-rating of load at Mangere (MNG)
- modelling changes that better reflects actual demand response at NZ Steel's Glenbrook (GLN) site.

The Nova Otorohanga peakers were not reflected in the modelling because the Authority did not seek for its indicative modelling to reflect all consented and announced generation. The Authority modelled the impact of a 25MW expansion to Ngawha generation on charges because this was specifically requested by parties. Further, given the modelling was for the 2020 calendar year, any generator expected to be commissioned after that would not feature in the modelling. Genesis Energy announced in 2016 that the 500MW at Huntly will remain in operation until the end of 2022, so since the modelling was indicative charges for the 2020 calendar year this Huntly generation was included in the modelling.

Other than the exceptions described above, the modelling for the supplementary consultation paper reflects the modelling for the second issues paper. The modelling approach is described in Appendix B of the second issues paper. Refer specifically to paragraphs B.4 to B.5 for the assumptions used to model generation. The modelling assumes that Otahuhu B and Southdown are not available, but that a new 50MW geothermal plant will be commissioned near Wairakei at the start of 2019, in order to meet demand growth. Refer also to paragraphs B17 to B27, which address generation assumptions in more detail.

2. Input assumption changes and/or calculations relating to any GXP Demand and Anytime Maximum Demand (AMD) calculations made between the prior and the latest issue of TPM cost allocations. In particular, those calculations relating to the material differences for Networks or Direct Connections served by Distributed Generation and Cogeneration plant.

Gross AMD was based on 2014 data for the supplementary consultation paper. This approach is unchanged from the modelling in the 2nd issues paper. However, the Authority made a number of amendments to parties' gross AMD's in the modelling for the supplementary consultation paper. These are listed below:

- Buller Electricity reduced from 28.4MW to 12.7MW: Adjustment to reflect
  - Holcim Cement's exit from Westport, and
  - aggregation of load at Orowaiti
- Carter Holt Harvey (now Oji Fibre) reduced from 88.9MW to 0MW: In the Authority's modelling for the second issues paper, indicative transmission charges were modelled for some embedded large consumers, such as Oji Fibre, which is a customer of Powerco. The Authority provided separate charges for certain embedded large industrials to assist those parties to understand the potential implications the Authority's proposal. In practice, the way transmission charges are passed on to such consumers is a matter for distributors and the particular customers. Gross AMD was moved to Powerco to reflect the point that Oji Fibre is embedded. Thus, Oji Fibre's indicative charges were rolled up into Powerco's charges
- Electricity Ashburton reduced from 197.2MW to 165.7MW: Adjustment to reflect aggregation of load at Ashburton
- Electricity Invercargill increased from 55.6MW to 61.3MW: Previously gross AMD was calculated by splitting the INV0331 load by energy demand over the year as an approximation. The new approach uses half hourly data and is more accurate
- Norske Skog reduced from 114MW to 93MW: A change to gross AMD to reflect netting of onsite generation
- Northpower increased from 138.2MW to 172.8MW: Refinery NZ was moved to Northpower to reflect that it is an embedded customer. Note, the same explanation as provided above in relation to Carter Holt Harvey applies
- NZ Steel reduced from 170.4MW to 136.8MW: A change to gross AMD to reflect netting of onsite generation
- Pacific Steel increased from 0MW to 16.8MW: An increase based on new information provided that the plant is running
- Powerco increased from 984.2MW to 1,095MW: Carter Holt Harvey's gross AMD moved to Powerco
- Refinery NZ reduced from 35.6MW to 0MW: Moved to Northpower
- Top Energy reduced from 72.3MW to 48.6MW: 25 MW removed from demand based on the 25MW Ngawha expansion, due to an assumed permanent change in demand
- Westpower reduced from 74.4MW to 61.4MW: Adjustment to reflect
  - Oceania mine's exit from Reefton (a permanent change in demand), and
  - aggregation of load at Reefton.

Appendix 2: Pioneer submission on 2nd Issues paper - matters as yet unresolved in the Supplementary information of 6 December 2016

Pioneer Energy made a submission on the TPM 2nd Issues paper made on 26th July 2016. In that submission Pioneer highlighted some fundamental concerns with the Electricity Authority's 2nd Issues Paper proposal. Pioneer remains concerned that the Authority has not discussed or addressed the following issues in their supplementary consultation or revised Guidelines:

- The Authority has ignored "economic sizing" principals in its proposed allocation of the costs of large transmission infrastructure – ignoring economic sizing reduces the economic efficiency of allocating costs on the basis of private benefits at a single point in time.

- The Authority, in its economic value analysis, has ignored long standing engineering knowledge and industry practice for the design and planning of the transmission system. Loss of, or weakening of, peak demand price signals will have serious long term cost implications for consumers.

- Oakley Greenwood's independent Cost-Benefit Analysis (CBA) has serious shortfalls; overestimating future generation and transmission co-investment benefits to consumers and underestimating existing consumer benefits attributable to strong peak demand price signals. The generation inputs and methodology used for the future scenarios are insufficiently robust or durable to justify the resulting significant wealth transfers.

- The Authority is diluting natural competition for transmission capacity, by making the transmission costs unavoidable. The economic arguments made for maximizing the use of over-built transmission assets runs against the government's own NZEECS policy and consumer incentives to reduce energy use and energy costs. The long-term benefits to consumers are thus ambiguous and tenuous at best, whilst the up-front costs to consumers from the changes to the allocation of transmission costs are very clear.

- The unintended consequences of removing peak demand price signals and increasing the physical system's efficiency losses are an order of magnitude higher than the potential economic efficiency gains of this TPM proposal. A simple comparison was made in Pioneer's submission on the TPM CBA benefits that makes it very clear the proposal has no long-term consumer cost-benefits, but instead only creates short term wealth transfers from small consumers to large Generators and Rio Tinto.

- Transpower's submission indicates the inefficiency in the current transmission charges is significantly less than the likely impact of weaker peak demand price signals on system energy losses and generation capacity cost inefficiencies. Pioneer provided this information in its 2nd Issues Submission[3].

[3] Pioneer TPM Submission – paragraphs 28 – 32, page 8 and Table 3.1 and paragraphs 22 – 24 in Schedule 2 – Market Analysis of Grid Alternative Benefits.

- Pioneer, in a letter of 3 October 2016 and in its submission on the Customer Compensation Scheme in December, presented further evidence that nodal energy spot pricing is not efficiently signaling system demand marginal costs, but is exhibiting characteristics of market power by a small number of hydro Players. Further, nodal spot pricing has failed to efficiently signal security of supply risks – for example, the Huntly exit scenario and sudden loss of OTA CCGT in 2016.

Numerous other submitters have expressed similar concerns to those of Pioneer; on the lack of historical and empirical evidence; on the weakening of market pricing signals; and on the poorly contrived CBA. These concerns have, for the most part, been either dismissed light-handedly or just ignored by the Authority.

Pioneer is seeking further empirical analysis from the Authority, using historic rather than forecast information that supports its key market assumption that replacing transmission peak price signals with energy spot signals will result in lower future investment costs and further empirically derived evidence in the Authority's final TPM decision report supporting the co-investment efficiency benefits claimed.