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SUBMISSION ON THE TRANSMISSION PRICING REVIEW: 2019 ISSUES PAPER

Rio Tinto welcomes the opportunity to provide a submission to the Electricity Authority (Authority) on its consultation paper entitled, "2019 issues paper, Transmission pricing review" dated 23 July 2019. This submission is made by Rio Tinto on behalf of Pacific Aluminium (New Zealand) Limited and New Zealand Aluminium Smelters Limited (NZAS). Nothing in this submission is confidential.

Rio Tinto has ownership interests in four smelters in Australasia, including NZAS which it owns 79.36 per cent of in a joint venture with Sumitomo Chemical Company, Limited of Japan. NZAS was opened in 1971 at Tiwai Point near Invercargill in Southland and, although it has operated for 48 years, remains a world class smelter in its technical capability. NZAS is unique, being the only smelter in the world to produce high purity aluminium using renewable power.

The major differentiator of the competitiveness for any smelter is the cost of power as it makes up a large proportion of its input costs and is not internationally traded. Compared with its international competitors, NZAS faces very high power costs. The cost of transmission to NZAS is as much as ten times the cost faced by other smelters, particularly those located as close to the main source of power as NZAS is. As aluminium is an internationally traded commodity NZAS has no choice but to absorb those costs which means NZAS struggles to achieve long term commercial sustainability.

NZAS was established in collaboration with the New Zealand government, and provided the foundation load for the Manapouri power station. The owners of NZAS committed to constructing the smelter and to repay the cost of constructing the power station and the transmission lines connecting it to NZAS. It remains the case today that the majority of the power delivered to NZAS is generated by the Manapouri power station and transmitted across those lines, which we estimate make up around 1.4% of all transmission lines in New Zealand. NZAS has contributed towards the cost of transmission for all its 48 years and for the past several years has been paying transmission costs which equal or exceed the entire book value of those assets every single year.

From the mid-2000's Transpower committed to a major investment programme, mainly designed to upgrade transmission infrastructure in the upper North Island, particularly Auckland. Prior to that time, the value of transmission assets in each of the islands was roughly proportionate to the charges to customers in each island. However this major investment programme changed all that. Although most of the investment was for the benefit of the upper North Island, the Transmission Pricing Methodology (TPM) ensures that Transpower' s revenue for those assets is collected from customers throughout the country, regardless of whether they benefit from those assets.

After 2008, NZAS saw significant increases in its annual transmission charges as these new investments were commissioned. Given electricity is a major input for an aluminium smelter, this has had a material impact on the business.

Rio Tinto has supported the Authority's efforts to reform the TPM since its formation in 2010. The 2019 issues paper is the Authority's third attempt to redefine the TPM guidelines and follows many years of research, working papers and modelling. Rio Tinto continues to support the Authority's TPM review and agrees with the Authority's view that the current TPM has significant flaws that are leading to inefficient investment and consumption decisions. The passage of time means that investments that were planned when Rio Tinto first identified issues with the current TPM and were in construction when the Authority commenced its review are now pre-2019 investments. Rio Tinto supports the Authority's view that a TPM that charges customers for the assets they benefit, including assets built before 2019, will lead to more efficient outcomes. It is also fairer.

However, Rio Tinto is concerned that the Authority's latest proposal has flaws, inconsistencies and a lack of transparency that raise concerning questions about what objectives the Authority is seeking to achieve.

The Authority has adopted an approach to the charging for pre-2019 assets that is inconsistent with its own principles that benefits-based charging should take account of net private benefits. For example, the approach will result in NZAS being allocated a material portion of HVDC charges despite the Authority's own modelling estimating a net benefit of *minus* $47m over the 4 year period of its study. Rio Tinto is not satisfied that the Authority has provided a coherent rationale for its decision.

The Authority has selectively limited the pre-2019 assets to which it has applied a benefits based charge, most notably excluding the North Auckland and Northland project. However, the Authority has declined to produce any analysis to support its proposal. Furthermore, the Authority's description of how it has treated reliability benefits leads to the concern that the benefits of certain assets have been materially understated.

The Authority's proposal would result in the majority of transmission revenue for assets being deemed a residual amount, to be recovered using a tax-like charge to all load customers, regardless of which customers the assets were constructed for or who benefits from them. This will necessarily undermine the efficiency of the new TPM and is compounded by the Authority's proposal to limit the breadth of the "tax-base" to load customers rather than spreading the charge across all customers.

In addition to issues with the approach to determining benefit-based and residual charges, the Authority proposes to cap the increases in charges to those customer that have thus far been the biggest beneficiaries of the current TPM. The cost of that cap will be subsidised by new payments from those customers who are already most disadvantaged by the current TPM. This component of the Authority's proposal would see NZAS paying a subsidy of $1m per annum for other industrial customers, some of which have been paying little to nothing for their use of the national grid. Not only is there no economic rationale for this but it is grossly unfair.

The Authority estimates its proposal could be implemented by 2024, if the TPM guidelines proposed in the 2019 issues paper are approved by April 2020. Given the Authority's usual timeframes for consulting on its proposals it would seem likely this timeline would only be achieved if the currently proposed guidelines are approved largely in their current for. However, as Rio Tinto has pointed out, there remain significant issues that the Authority ought to address.

Given the Authority's current proposal, NZAS can expect to continue to face excessive transmission charges until at least 2024 and, if the TPM is revised in accordance with the current proposal, would thereafter be expected to pay an ongoing subsidy for other industrial customers as well as significant residual charges that cover assets it does not benefit from. Rio Tinto continues to encourage the Authority to progress its TPM review with the utmost urgency, though Rio Tinto can no longer rely on the review to deliver appropriate and timely relief from very high transmission charges for NZAS.

Please find our submission on the 2019 issues paper attached to this letter. Should you have any enquiries, please do not hesitate to contact Lesley Silverwood, Director Energy, Rio Tinto Aluminium at lesley.silverwood@riotinto.com.

Yours sincerely,

Jennifer Nolan
Director External Relations, New Zealand

A submission from

Rio Tinto

to the Electricity Authority on the

2019 issues paper

Transmission pricing review: consultation paper

1 October 2019

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Executive summary

1. Rio Tinto welcomes the opportunity to make a submission to the Electricity Authority (Authority) on its 2019 issues paper, Transmission pricing review: consultation paper, 23 July 2019 (2019 Issues Paper).

2. We agree that those who benefit from specific grid investments should pay for them. We support the concept of a:
    a. benefit-based charge, to recover the costs of new grid investments and major existing investments, based on the benefits those investments provide to transmission customers
    b. residual charge to recover any remaining transmission costs in a manner that does not distort incentives to invest or use the grid.

3. Rio Tinto agrees that, if the key features described above were reflected in transmission charges, the new charges would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives. We agree that making these changes to the transmission pricing methodology (TPM) is necessary and urgent for the reasons summarised by the Authority—namely, the flaws in the existing TPM are leading to inefficient investment and consumption outcomes, and the economic cost of those distortions is compounding.

4. However, the pricing proposals as reflected in the draft “Proposed TPM Guidelines” contain serious flaws and inconsistencies. These flaws and inconsistencies are due to the Authority:
    a. Failing to apply its own proposed TPM Guidelines and reasoning in specifying charges for specific investments completed prior to 2019.
    b. Misreading its statutory purpose statement as it applies to rules that transfer wealth between different transmission customers.
    c. Not specifying a Prudent Discount Policy that would achieve its intended purpose.
    d. Applying a different valuation method to setting the prices for post-2019 assets than the Commerce Commission applies in setting allowable revenue.

Failing to apply its own draft Guidelines and reasoning

5. The charges specified in Schedule 1 of the draft Guidelines would form a very specific numerical regulation to fix the proportion of charges for pre-2019 assets each customer must pay. However, those proportions were not calculated by applying the concepts and principles set out in the 2019 Issues Paper. The choices by the Authority to not carry forward negative benefits, to apply reduced (and possibly varying) values for reliability, and its selection of modelling years, are in effect manual adjustments by the Authority that reallocate large sums of money between transmission customers. In the absence of a robust explanation, these adjustments risk the impression the Authority was solving for a pre-determined, and undisclosed, outcome. In addition, the modelling that determines these charges does not reflect the realities of the New Zealand transmission grid and hence the benefits it provides.

6. The Authority stresses the importance of durability of the TPM. By not establishing that its proposed charges follow from its analysis, and by not explaining why it has not followed its own analysis, the Authority undermines its credibility and hence the durability of its regulatory decisions.

Misreading its statutory purpose statement

7. The Authority interprets its statutory objectives as being synonymous with a net efficiency objective. Rio Tinto agrees that the Authority should not be making decisions that reduce economic efficiency. However, this does not mean that the Authority can be indifferent to, and not take account of, wealth transfers. Promoting the long-term benefit of consumers is central to the Authority's purpose statement. This means the Authority should favour options that provide long-term benefits to consumers over those that do not, where there is no material efficiency loss from doing so.

8. Recognising that the long-term benefit of consumers is central to the Authority's purpose statement has important implications for the design of the TPM:
   a. There is no support in the purpose statement for the Authority to require some commercial customers to subsidise other commercial customers.
   b. The benefits of benefits-based charges, and especially extending the charges to existing assets, are likely materially understated.
   c. The residual charge mechanism should not exempt existing generators.

Prudential discount

9. In developing its prudent discount policy, the Authority references accepted economic theory that any charge should be between incremental and stand-alone cost. In the Authority's workably competitive market analogy, an entity would not be able to exploit a statutory monopoly (for example, a resource consent for a transmission corridor) to charge more than the standalone cost of a service. To meet the principles it says underpins its approach, and that would achieve its statutory objective, the Authority needs to reintroduce into the proposed prudential discount a provision for the discount to apply so that a transmission customer does not pay more than the standalone costs of the transmission services it receives.

Inconsistent valuation of post-2019 assets

10. The proposed draft TPM Guidelines would recover post-2019 investments using a different valuation method from the method used by the Commerce Commission in setting Transpower's recoverable revenue, with the difference being absorbed by the residual charge. The Authority provides no quantitative or qualitative reasoning to support its statement that the efficiency benefits from pricing new assets using indexed historical cost would exceed the efficiency losses from increasing the residual charge for all other assets. The Authority's conclusion is improbable for three reasons:

    a. The efficiency losses are incurred up front, while the benefits are deferred.

b. The approach undermines the certainty consumers expected from the Commerce Commission's Input Methodologies; the Authority makes no attempt to reconcile its own statutory obligation to regulate for the long-term benefit of consumers with its undermining of a statutory benefit intended for consumers.

c. The approach would result in significant inter-temporal wealth transfers that are not considered by the Authority.

There are some improvements to the 2016 concept

11. In the three years since releasing its 2016 Issues Paper, the Authority has made some improvements to its conceptual design and its reasoning in support of that concept. Notably, Rio Tinto supports the following changes in the 2019 Issues Paper relative to the 2016 Issues Paper. The 2019 Issues Paper:
    a. Acknowledges that how the costs of existing assets—as well as the costs of new investment—are recovered is important to meeting the economic efficiency requirements of the Authority's statutory objective.
    b. Recognises the role of nodal prices in signalling efficient marginal costs, and hence additional Long Run Marginal Cost (LRMC) based charges are unnecessary.
    c. Adopts a valuation method for setting charges for pre-2019 investments consistent with the valuation method used by the Commerce Commission in setting Transpower's revenue requirements.
    d. Would require Transpower to recover through the benefit-based charge any operating costs attributable to the relevant investment, so that only common costs were recovered through the residual charge.

Conclusion

12. Rio Tinto continues to support the introduction of benefits-based charges. We agree that those who benefit from specific grid investments should pay for them. We agree with the Authority that benefits-based charging would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives.

13. However, in developing specific proposals, and especially the charges for existing assets, the Authority fails to apply its own proposed TPM Guidelines and reasoning. The charges specified in Schedule 1 of the draft Guidelines would form a very specific numerical regulation; the modelling undertaken by the Authority to support those regulations is not fit for purpose.

Move to benefit-based charges is necessary and important

1. Rio Tinto agrees with the Authority that those who benefit from specific grid investments should pay for them. We support the key features of the proposal to require Transpower to reflect this beneficiary pays principle in setting its transmission charges by introducing a:
   a. benefit-based charge, to recover the costs of new grid investments and major existing investments, based on the benefits those investments provide to transmission customers
   b. residual charge to recover any remaining transmission costs in a manner that does not distort incentives to invest or use the grid.

2. Rio Tinto agrees that, if the key features described above were reflected in transmission charges, the new charges would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives. We agree that making these changes to the transmission pricing methodology (TPM) is necessary and urgent for the reasons summarised by the Authority—namely, the flaws in the existing TPM are leading to inefficient investment and consumption outcomes, and the economic cost of those distortions is compounding.

3. In the three years since releasing its 2016 Issues Paper,[1] the Authority has made some improvements to its conceptual design and its reasoning in support of that concept. Notably, the proposal in the 2019 Issues Paper now:
   a. Acknowledges that how the costs of existing assets—as well as the costs of new investment—are recovered is important to meeting the economic efficiency requirements of the Authority's statutory objective. Rio Tinto agrees with this analysis for the reasons set out in Pacific Aluminium's submission on the Authority's Second Issues Paper.[2]
   b. Recognises the role of nodal prices in signalling efficient marginal costs, and hence additional Long Run Marginal Cost (LRMC) based charges are unnecessary. Rio Tinto agrees with this analysis, for the reasons set out in Pacific Aluminium's submission on the Authority's Second Issues Paper.[3]
   c. Adopts a valuation method for setting charges for pre-2019 investments consistent with the valuation method used by the Commerce Commission in setting Transpower's revenue requirements. Rio Tinto agrees that the valuation methods should be consistent across revenue and price setting, for the reasons set out in Pacific Aluminium's submission on the Authority's 2016, supplementary consultation paper.[4]

[1] Electricity Authority, Transmission Pricing Methodology Review: Issues and Proposal: Second Issues Paper, 17 May 2016, and Transmission Pricing Methodology Review: Issues and proposal: Supplementary consultation paper, 13 December 2016.
[2] Pacific Aluminium, (2016), Submission to the Electricity Authority on Transmission Pricing Methodology Review: Issues and Proposal: Second Issues Paper, 17 May 2016, pages 15 – 16.
[3] Pacific Aluminium, (2016), Submission to the Electricity Authority, ibid, pages 13 – 15.
[4] Pacific Aluminium, (February, 2017), Submission to the Electricity Authority, Transmission Pricing Methodology Review: Issues and proposal: Supplementary consultation paper, 13 December 2016, pages 19 –

d. Require Transpower to recover through the benefit-based charge any operating costs attributable to the relevant investment, so that only common costs were recovered through the residual charge. Rio Tinto agrees that all costs attributable to an investment should, as much as practicable, be recovered through its benefit-based charge for the reasons set out in Pacific Aluminium's submission on the Authority's Second Issues Paper.[5]

4. However, the pricing proposals as reflected in the draft "Proposed TPM Guidelines" contain serious flaws and inconsistencies. These flaws and inconsistencies are due to the Authority:
    a. Failing to apply its own proposed TPM Guidelines and reasoning in specifying charges for specific investments completed prior to 2019.
    b. Misreading its statutory purpose statement as it applies to rules that transfer wealth between different transmission customers.
    c. Not specifying a Prudent Discount Policy that would achieve its intended purpose.
    d. Applying a different valuation method to setting the prices for post-2019 assets than the Commerce Commission applies in setting allowable revenue.

5. Rio Tinto explains each of these flaws below.

Failure to apply TPM Guidelines and reasoning in charges for pre-2019 investments

Benefits-based charges for selected pre-2019 investments

6. The Authority concludes that benefit-based charges should be applied to seven major existing investments.[6] Rio Tinto agrees with the Authority that recovering the costs of these investments (and other pre-2019 investments) using the benefits-based charge would promote its statutory purpose as:
    a. better signals would be sent to consumers about the economic cost of using the grid if Transmission charges are set on the basis of beneficiary pays[7]
    b. pricing arrangements are more durable "when you pay for what you get"[8]
    c. durability would be undermined if consumers in some regions would have to pay both for new investments made for their benefit and continue to pay for major investments they didn't benefit from[9]
    d. grandparenting would tend to provide preferential treatment to some incumbents and would reward inefficient actions[10]

30, and Pacific Aluminium, (March, 2017) Transmission Pricing Methodology: Second Issues Paper: Supplementary Consultation: Cross submission on valuation method.

[5] Pacific Aluminium, (February, 2017), ibid, page 43.

[6] These investments are the HVDC, North Island Gid Upgrade, Upper North Island Dyanamic Reactive Support, Wairakei Ring, Bunnythorpe-Haywards Reconducturing, Lower South Island Reliability, and Lower South Island Renewables.

[7] Electricity Authority, (2019) ibid, page iii.

[8] Electricity Authority, (2019) ibid, page iv.

[9] Electricity Authority, (2019) ibid, page iv.

e. a compromise on historic investment would undermine the durability of the TPM.[11]

7. However, for reasons the Authority does not explain, its proposal would compromise on charges for historic investments in a manner that would reward inefficient actions and undermine the durability of its proposals. The Authority proposes that seven major existing investments should be priced on a modified benefits-based charge compared to new investments, but offers no explanation for the difference in approach. We outline the differences in approach below and explain why these differences undermine confidence in the durability of the Authority's rule-making.

Benefit-based charge for post-2019 investments

8. The draft Guidelines provide for Transpower to set its charges for investments commissioned after the publication of the 2019 Issues Paper in proportion to the positive net private benefit each customer is expected to receive from that investment.[12] Net private benefit, for a customer, is defined as:[13]
    a. The value of the private benefit the customer is expected to receive from the investment, *less*
    b. The value of the private costs the customers is expected to incur as a result of the investment (not including cost of the investment itself).

9. Private benefits and costs are determined by reference to "electricity market benefit or cost element" as defined in the Commerce Commission's *Transpower Capital Expenditure Input Methodology Determination*. Electricity market benefit or cost element are concepts used by Transpower (and the Commerce Commission) in evaluating transmission investment proposals. The terms refer to the economic benefits (and costs) that consumers might experience as a result of a transmission investment, including:[14]
    a. changes in generation fuel costs
    b. the costs of involuntary demand curtailment
    c. the cost of transmission losses and ancillary services
    d. competition effects.

10. Rio Tinto agrees that net private benefits, for the purposes of setting the benefits-based charge, should be estimated on the same basis as Transpower estimates private benefits and costs for the purposes of evaluating transmission investments. Cross-referencing these definitions would ensure that when any weaknesses in the specification of private benefits are addressed, they are corrected for both evaluating and pricing the investment.

11. The draft Guidelines would also require Transpower to make it clear exactly how it has calculated a transmission customer's transmission charge.[15] Rio Tinto agrees that transparency is important to the credibility of the pricing regime, and that a customer should

[10] Electricity Authority, (2019) ibid, page iv, footnote 7.
[11] Electricity Authority, (2019) ibid, page v.
[12] Electricity Authority, (2019) ibid, Appendix A, Draft TPM Guidelines, clause 22(a).
[13] Electricity Authority, (2019) ibid, Appendix A, Draft TPM Guidelines, clause 66.
[14] For the full defintion, see clause D 4 (1), of Commerce Commission's (2018) *Transpower Capital Expenditure Input Methodology Determination.*
[15] Electricity Authority, (2019) ibid, Appendix A, Draft TPM Guidelines, clause 6.

have the information needed to verify the accuracy of Transpower's calculation of its transmission charges.

Authority applies different measure of benefit for pre-2019 investments and does not explain why

12. The Authority applies a different method for setting charges for the pre-2019 investments from post-2019 investments. Rather than require Transpower to calculate the charges for the seven existing investments on the basis of net private benefit, as would occur for new investments, the Authority specifies the proportion of the cost of those investments that Transpower must recover from each customer. These proportions are listed in schedule 1 of the draft TPM Guidelines. In calculating the proportions each customer would pay, the Authority has not applied the same methodology that it would have Transpower apply under the draft Guidelines.

13. Using the vSPD model, the Authority estimates the price and quantity consumers would purchase with the investment in place (the factual scenario) and the price and quantity they would buy without the investment in place (the counterfactual scenario). From these different price and quantity combinations, the Authority estimates the difference in producer and consumer surplus between the factual and counterfactual. Consumer surplus measures the difference between the amount consumers would willing pay for a good or service and the amount they pay. Supplier surplus measures the difference between the amount for which suppliers are willing to sell a good or service and the amount they receive for it.

14. Hence, the Authority appears to only model competition benefits in the way it has assessed beneficiaries for existing assets. This narrowing of the concept of benefit by the Authority is a concerning precedent set by its modelling. One of the purposes of including historical investments in a benefits-based charge is so that, in the future, parties advocating for investments would know that, if they are beneficiaries of the investment, they will pay. However, the Authority's approach would set a precedent where future beneficiaries of reliability focused investments could advocate for an investment and argue that they should only be allocated costs on the basis of how much they benefit from competition.

15. In response to questions about the modelling of benefit charges and whether reliability was catered for the Authority responded that: "With respect to allocating the costs of historical investments, our view is that promoting durability (and efficiency) does not require a highly precise allocation of the costs of historical investments. Accordingly, our view is that it is reasonable to use a proxy for total benefits in allocating historical investment costs, and it is reasonable to not separately quantify reliability and other benefits in allocating the costs of the seven historical investments."[16] Given that the Authority has used a modelling approach that has used deterministic optimisation techniques to solve 70,000 half-hour periods at over 250 nodes using a significant number of input assumptions to produce results to four significant places then we would argue that the proposed calculation is already too precise. It is accuracy that is the problem.

[16] Email correspondence from the Elecricity Authority dated 20 September 2019

16. We are not comforted by the Authority's view that it is reasonable to use a proxy for total benefits. The Authority has used supposition and 'views' to determine so many of the assumptions and interpretations that the 'modelled' output is simply the Authority's postulation.

17. The Authority chose to estimate the average change in competition benefits—consumer and producer surplus—over a four-year period (we comment on the choice of this four-year period below). It calculates this average by summing only net positive consumer, or producer (as the case may be), surplus for each transmission customer for each year over the four-year period and dividing by four. This average is then taken as a percentage of the total sum of the average benefits derived by all transmission customers from that investment; the resulting percentage is the proportion of the cost of the investment that would be paid by that customer. For example, a customer that is assessed as obtaining 5 per cent of the benefit from the investment, on average, would be charged 5 per cent of the cost of that investment.

18. In the case of the HVDC, the Authority calculated the benefits accruing to the NZAS as $65 million, which is 7.25% of the total sum of benefits derived by all transmission customers. Hence, NZAS would be required to pay 7.25% of the cost of the HVDC.

19. The approach adopted by the Authority is at odds with its benefits-based charge methodology specified in the draft Guidelines, and explained in the 2019 Issues Paper, in at least three important regards:
    a. the Authority does not estimate *net* private benefit
    b. it discounts heavily reliability benefits, though those anticipated benefits were the primary driver for many of the investments
    c. it assumes that the four-year period is representative
    d. it is not transparent as to exactly how it has calculated the charges.

Not an estimate of *net* private benefit

20. In its modelling, the Authority does not estimate the **net** private benefit a customer receives from the pre-2019 investment, though it calculates the information it needs to make such an assessment. The spreadsheets released by the Authority reveal that in summing up the estimated benefits received by NZAS, the calculations implement a rule that a net negative benefit cannot be carried over from one 12-month period to the next 12-month period.[17] This rule is implemented by only summing positive net benefits for each year of the four-year period.

21. To illustrate, Table 1 shows the HVDC benefits the Authority estimates NZAS received in each of the four years. The first three years produced negative benefits. However, the rule

[17] Cell H26 in The Electricity Authority. (2019). *Illustrative benefit calculation spreadsheet*. Electricity Market Information. Accessed at https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2019/20190723_TPM_2019_IssuesPaper/vSPD_Excel_files

embedded by the Authority in its spreadsheet means these negative values are not carried forward. Hence, only the last year of the four-year period is counted in estimating the benefits to NZAS ($\frac{261{,}938{,}746}{4} = \$65\ million$).

Table 1 Electricity Authority calculation of consumer benefit of HVDC to NZAS

Run	Year	deltaCS	LOAD Benefit	Benefit
HVDC_Var_No Res_2014_2015	2014_2015	- 193,086,497	-	-
HVDC_Var_No Res_2015_2016	2015_2016	- 189,245,830	-	-
HVDC_Var_No Res_2016_2017	2016_2017	- 69,389,091	-	-
HVDC_Var_No Res_2017_2018	2017_2018	261,938,746	261,938,746	261,938,746

22. The calculation shown above is clearly different from that specified in the draft TPM Guidelines, in which *net* private benefit would be calculated by deducting private costs from private benefits (see discussion at paragraph 8 above).

23. In Table 2 below, we show the net private benefit to NZAS from the HVDC once private costs are deducted from private benefits. The result is that there is a substantial disbenefit of almost $190 million to NZAS. The average yearly *loss* in consumer surplus is $47 million. That is, NZAS is not a beneficiary of the HVDC investment based on the four-year sample.

Table 2 Corrected calculation of net private benefit of HVDC to NZAS

modelyear	node	generationMWh	loadMWh	deltaCS
2014_2015	TWI2201	0	4988800.354	-193086497.3
2015_2016	TWI2201	0	5033653.389	-189245830
2016_2017	TWI2201	0	5016641.283	-69389091.3
2017_2018	TWI2201	0	4990344.909	261938745.7
			Sum of deltaCS	- **189,782,672.98**
			Average of sum of deltaCS	- **47,445,668.24**

24. In its reply to Rio Tinto's questions, the Authority said it recorded negative benefits accrued in one year as zero because "the proposal is not to compensate parties who experience dis-benefits from an investment." That objective could have been achieved simply by recording any negative result from the average of the four separate one-year modelling periods as zero. By instead setting three of the four years to zero, the Authority grossly overstates the benefits NZAS derives from the investment. The Authority's method is equivalent to saying a business is profitable if it operated at a loss for three years and was profitable for one

25. There is no basis in economics, or in logic, for ignoring three years of consumer deficit and only counting the benefit from the last year from a four-year sample. As the Authority says in its 2019 Issues Paper:[18]

[18] Electricity Authority, (2019) ibid, Appendix B, paragarph B.112.

Consistent with what happens in workably competitive markets, we consider that charges should be set on the basis of net benefits from the investment, that is, benefits minus costs.

26. The Authority does not do what it says it will do when setting NZAS's charge for the HVDC. The Authority's shift of $7.17 million of HVDC charges to NZAS (7.25% of the $99 million to be recovered from the HVDC investment) is not supported by its reasoning.

HVDC modelling is inconsistent with its approach to other assets

27. The Authority proposes that only seven major investments of the 2000's (summarised in Table 15 in Appendix H) be included in the benefit-based charges. Rio Tinto maintains that all assets should be considered for a benefit-based charge, a principle that the Authority has resisted. Yet, when considering the HVDC, the Authority also removes Pole 2 from its counterfactual scenario. Pole 2 has been in service since 1992 (in the case of the converter equipment and undersea cables) and 1965 (in the case of the overhead line).

28. This modelling assumption is inconsistent whichever way it is looked at. Either only recent investments should be included, and therefore the counterfactual for the HVDC analysis should be with Pole 2 in service without a control system upgrade. Or, alternatively, that any historical asset can be considered for benefit-based charging.

29. The explanation provided by the Authority for removing Pole 2 in its entirety is that: "The Authority decided to group Poles 2 and 3 of the HVDC on the basis that they essentially provide a single function."[19] This same justification could be made for the circuits in parallel to the NIGU project, or any of the projects considered for the benefit based charge. The Authority seems to be trying to achieve an undisclosed outcome rather than consistently apply principles.

30. We also note that the Authority did not assume that there was a VPO generator in the South Island for the removal of the HVDC on the basis that they "did not assume a VPO elsewhere"[20] even though this is the only scenario where there was islanding of part of the power system. Inevitably, without a swing bus in the islanded system, the Authority modelling computed prices in excess of $10,000/MWh which were simply "considered infeasible and removed."[21] We do not consider this to be good modelling practice.

Reliability investments heavily discounted

31. Several of the pre-2019 investments were implemented for reliability reasons. The Authority's modelling does not capture, or heavily discounts, reliability benefits and attributes costs based almost entirely on competition benefits.

32. Transmission investments are based on prudent demand forecasts and often result in capacity that is expected to be more than is required. In transmission economics this prudent capacity has real option value for consumers, even if the capacity is not ultimately

[19] Electricity Authority, (2019) ibid, Appendix H, paragraph H.68.
[20] Electricity Authority email of 20 September 2019
[21] Ibid

utilised.[22] The Authority's modelling approach does not capture the option value of prudent capacity, or indeed any future growth. Under the Authority's beneficiary assessment, the transmission investments that would best demonstrate benefits commensurate with costs would be those that just meet expected demand growth, even though slightly different growth rates might result in lost load.

33. In justifying reliability investments, Transpower applies a value of lost load (VoLL) of $20,000 per MWh. This estimate of VoLL is set by clause 4 of schedule 12.2 of the Electricity Participation Code.

34. In answers to questions at its Wellington stakeholder workshop on Friday, 23 August 2019, the Authority explained that it did not apply the estimate of VoLL specified by the Code when estimating the reliability benefits of the pre-2019 investments. Rather, it advised that it made adjustments to its vSPD scenario modelling (discussed in paragraph 13 above) to increase nodal prices when the grid became constrained in the counterfactual. The Authority did not provide further information on the magnitude of those adjustments nor how the adjustments were determined. We assume that this adjustment was the virtual price offer described in Appendix H of the 2019 Issues Paper, being $500/MWh or the Authority's preferred limit of constraining any price increase to 20%.[23]

35. Clause 4 of schedule 12.2 provides for the Authority to determine different values of unserved energy for different purposes and at different times. However, if the Authority determines a different value for unserved energy, it must publish its determination. Rio Tinto is not aware of any determination published by the Authority setting out an estimate of VoLL that it would use in setting the charges for pre-2019 investments. Rather, the Authority has made unexplained adjustments to its modelling of private benefits.[24]

36. It certainly appears that the values used by the Authority are substantially less than the values it required Transpower to use when assessing the merits of the investments—this presumption follows the Authority's finding that it was not able to identify material benefits for transmission customers commensurate with the costs of the North Auckland and Northland (NAaN), Otahuhu Substation Diversity and Upper South Island Reactive Support investments.[25] The Authority confirmed in its response to our questions that no vSPD modelling was undertaken as it was apparent to the Authority that these investments provided no material benefits during the modelling period. Speculation of this nature is not a sound process for setting charges. The Authority should provide an empirical result to support its decision to discount this project from a beneficiary-based charge.

[22] Baumol, William J. and Sidak, J. Gregory, The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?. Energy Law Journal, Vol. 23, pp. 383-399, 2002.

[23] Removing the modelled investments from the counterfactual results in infeasibilities without applying replacement energy offers to make up for any missing delivered energy. We assume the Authority has applied virtual price offers either limiting price increases to 20% or using $500/MWh (from Appendix H of the 2019 Issues Paper), whereas any lost load under reliability assessments would have been valued at VOLL ($20,000/MWh).

[24] While the Authority has explained the virtual price offers it used in the 2019 Issues Paper it has not explained how these are suitable adjustments for assessing reliability benefits, or if there were other adjustments made for this purpose.

[25] Electricity Authority, (2019) ibid, Appendix H, paragraph H.67.

37. The NAAN interconnection is complicated. It can be essential in enabling flexibility and reduced risk in relation to outages on the West Auckland overhead lines and is also integral to Auckland voltage management. In addition, some of Vector's lines are in parallel with NAAN and these parallel circuits are not modelled in vSPD. Based on the Authority's modelling configuration for NIGU (using the upper North Island stability constraint as it was on 21 July 2009), the security constraint assumptions for the modelling, in the absence of Southdown and Otahuhu, could be wrong. In the absence of information about how NAAN is modelled by the Authority, we are not confident that it has been modelled correctly to identify competition benefits. We are certain that the modelling failed to identify the beneficiaries of reliability.

38. We note that many of the reliability issues, especially voltage and outage management, become more acute as Auckland grows; which is another factor ignored in the way that the Authority has modelled benefits.

39. We have similar concerns with the modelling of the Otahuhu Substation Diversity project. Simply trying to assess a deprival value for this project is unlikely to work. If this link were removed, much of Auckland would be reduced to N-1 security where it currently benefits from at least N-2. Of course, a model that only assesses competition benefits would not estimate this loss of benefit. Based on Transpower's System Security Forecasts, Auckland voltage would likely be unmanageable without this link; this is because NIGU would effectively become a double circuit spur line and provide no support to Penrose or Otahuhu substations. But vSPD would solve this solution without realistic voltage stability constraints. This counterfactual is not realistic. NIGU would have to be changed to connect to Otahuhu; indeed, the Otahuhu Substation Diversity project should be bundled with NIGU to properly assess it. Again, the removal of Southdown and Otahuhu casts serious doubts on the use of historical configurations for the counterfactual.

40. The oddity of the Authority's approach is evident from its allocation of some of the cost of the NIGU upgrade to NZAS. Transpower's System Security Forecast indicates that NIGU is second only to Huntly unit 5 generation in helping Auckland avoid voltage collapse. Not considering reliability, and especially voltage in this case, greatly understates the reliability benefits to local beneficiaries. As the Authority needed to remove HOB_PEN_1 from the counterfactual to avoid overloading local 110kV lines,[26] then this indicates that the Authority did not have the requisite skill to redefine the design of the Penrose series reactor for the counterfactual. This casts serious doubt over the credibility of the modelling.

41. Rio Tinto is concerned that it is identified as a significant beneficiary of the LSI Renewables project, which we opposed. The project was intended to facilitate generation from new renewable projects to be exported out of Southland, as the name suggests.

Choice of four-year period unsupported

42. The charges that result for individual customers from the Authority's approach are very sensitive to the choice of years modelled. The Authority says that its chosen four-year

[26] Electricity Authority, (2019) ibid, Appendix H, paragraph H.89.

modelling period averages out variances from annual and seasonal patterns, without being outdated.[27] Basic visual observation by the Authority is used to support its claim that a four year period is representative.

43. The Authority does claim that the four-year profile matches more closely a decade-long hydrological profile than had it used the most recent two-year period.[28] However, the Authority does not explain why it did not use that ten-year period. Nor has it performed any sensitivity estimates of adding another year to the analysis, given the influence of 2017-2018 on the results (that is, a 1:5 ratio for 2017-2018 rather than 1:4).

Lack of transparency

44. The Authority considers that it would help customers in their decision-making if they are well informed about how their charges are calculated and are able to see how their charges evolve over time. It argues that better informed customers will in turn increase efficiency, producing long-term benefits for consumers.[29] Rio Tinto agrees with this reasoning and the conclusion the Authority reaches that customers should be able to determine exactly how their charges are calculated.

45. Unfortunately, the Authority's practice falls well short of the obligations it would impose on Transpower. It is not possible for NZAS to determine exactly how the charges it would occur under Schedule 1 of the draft Guidelines were calculated.

Inconsistency and lack of transparency undermine the durability of the Authority's proposals

46. The choices by the Authority to not carry forward negative benefits, to apply reduced (and possibly varying) values for reliability, and its selection of modelling years, are in effect manual adjustments by the Authority that reallocate large sums of money between transmission customers. In the absence of a robust explanation, these adjustments risk the impression the Authority was solving for a pre-determined, and undisclosed, outcome.

47. The approach taken by the Authority does not conform with best practice for the use of technical analysis to support regulatory decisions. The charges specified in Schedule 1 of the draft Guidelines ultimately comes down to a very specific numerical regulation. The overall picture is that the charges specified in Schedule 1 are not grounded in the concepts discussed in the 2019 Issues Paper, nor in the realities of the New Zealand transmission grid, but result from other, unspecified, objectives.

48. The Authority has stressed the importance of durability of the TPM. The development of the Code is an endlessly repeating process, the success of which depends on learning over time to make better regulatory decisions. In this evolution, the development of more reliable and sophisticated analytical methods over time is very important for learning how to make better decisions. Regulatory decisions are not like laboratory experiments, as they

[27] Electricity Authority, (2019) ibid, Appendix H, paragraph H.41.
[28] Electricity Authority, (2019) ibid, Appendix H, paragraph H.41.
[29] Electricity Authority, (2019) ibid, Appendix B, paragraph B.18.

take place in an evolving and changing environment, which means it is rarely certain in hindsight whether a particular regulation was a success or failure. In this process, it is important for the regulator to disclose what the analysis that was done at the time of that regulation showed, and reasons the regulator gave for substituting its own judgements in place of the analysis. The Authority has not established that the charges proposed in Schedule 1 followed from its analysis, nor explained why it has not followed its own analysis. That outcome undermines the Authority's credibility and hence the durability of its regulatory decisions.

Wealth transfers are relevant to long-term benefit to consumers

49. In explaining its approach, the Authority states:[30]

    The Authority does not take wealth transfers into account in making decisions.

50. There are two problems with this statement, and the flow-on consequences for the Authority's analysis.

51. Firstly, the statement is not an accurate explanation of the Authority's own interpretation of its statutory objective. As its interpretation makes clear, the Authority intends to take into account the efficiency effects that result from wealth transfers.[31] There is no evidence that the Authority has considered the efficiency effects of the wealth transfers that would result under its proposals (see the discussion below of the wealth transfers under the proposed price cap and inter-temporal wealth transfers resulting from differences in valuation approach).

52. Secondly, the Authority interprets the phrase "long-term benefit of consumers" in its statutory objective as synonymous with a net efficiency test. It based this interpretation—written 8 years ago—on the then prevailing interpretation of the purpose statement in Part 1 of the Commerce Act 1986. The Authority maintained that this interpretation would mean that the Authority's decisions would be consistent with expanding the size of the economic pie.[32]

53. Rio Tinto agrees that the Authority should not be making decisions that reduce economic efficiency; that is, reduce the size of the economic pie. However, this does not mean that the Authority can be indifferent to, and not take account of, wealth transfers. Promoting the long-term benefit of consumers is central to the Authority's purpose statement. Hence, if the Authority is faced with two options, both of which have the same efficiency effects, but one option would provide a long-term benefit to consumers then the Authority should favour that option over an option that does not provide long-term benefits to consumers.

54. Recognising that long-term benefit of consumers is central to the Authority's purpose statement has important implications for aspects of detailed design of the Authority's proposal and its cost benefit assessment. These implications include:

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[30] Electricity Authority, (2019) ibid, paragraph 4.61.

[31] Electricity Authority, *Interpretation of the Authority's statutory objective*, 14 February 2011, paragraph 2.2.1

[32] Electricity Authority, *Interpretation of the Authority's statutory objective*, 14 February 2011, paragraph A 7.

a. The Authority must assess and explain why its proposal to make explicit adjustments to the charges so that some customers pay more than they should to subsidise others is in the long-term interest of those consumers that would pay the additional costs.
b. The benefits of benefits-based charges, and especially extending the charges to existing assets, are likely materially understated (because the Authority moderates the impact of expected price changes to mitigate what would have been benefits to consumers but not generators).[33]
c. The residual charge mechanism excludes generators without accounting for the loss in long-term benefit to consumers (as well as not recognising the additional efficiency losses from excluding generators, as discussed below).

No basis for Authority to require NZAS to subsidise other consumers

55. The Authority proposes to cap the rate of change in transmission prices. The Authority proposes that other transmission customers, including NZAS, will, in effect, be levied to raise the funds needed to reduce the costs of selected transmission customers; that is, those customers whose charges would have increased by more than the cap. NZAS would pay an additional $1 million per annum more in transmission charges because of the cap.[34]

56. The primary beneficiaries of this cap are four major industrial consumers, that collectively would benefit by just under $15 million per annum.[35] Three small distribution utilities and another industrial customer would in aggregate benefit by under $1 million.[36]

Rio Tinto opposes the principle of an ongoing cross-subsidy from customers who have already been paying more than the efficient cost of their transmission services for many years while the TPM has been under review. The Authority does not explain how this cross-subsidy—that would result in some customers paying less than the efficient service-based and cost-reflective charge for the services they receive and other customers continuing to pay inefficiently high charges—would promote its statutory purpose.

Residual excludes generators to the long-term detriment of consumers

57. The Authority observes that the considerations in the design of the residual charge are the same as those obtained by following tax policy principles.[37] As with tax policy, the charge should be designed to minimise the incentives on users to alter their behaviour to try to reduce the charge they pay. Rio Tinto agrees with this framing of the issues, provided the

[33] Electricity Authority, (2019) ibid, pargraph 4.63.
[34] Electricity Authority, (2019) ibid, pages 61 - 62.
[35] These industrial customers are New Zealand Rail ($1.2 m), Norske Skogg ($5.4 m), NZ Steel ($6.1 m), Pan Pacific ($2.2 m). Resolution Dev would benefit by $0.012 m).
[36] The three distribution companies are Buller Electricity ($0.3m), Horizon Energy ($0.1 m) and Westpower ($0.2 m)
[37] Electricity Authority, (2019) ibid, footnote 330.

residual charge is small and the charge is not used to cross-subsidise transmission services received by other users (as discussed elsewhere in this submission, the Authority's proposal would recover through the residual charge costs that could and should be allocated through a benefits-based charge).

58. The starting point for minimising efficiency losses from any tax-like charge is to apply it to as broad a base as feasible. A broader base reduces the price increase necessary to recover a given amount of revenue. Minimising the price increase over and above the benefits-based charge is important because no tax-like charge can be truly non-distortionary, despite the Authority's efforts to design a fixed and unavoidable charge. The economic harm from raising tax-like revenue, such as the residual charge, increases more than proportionately as a tax-like charge increases. As a general approximation, if the tax-like charge doubles the economic costs associated with imposing that charge will approximately quadruple.[38] This result provides the basis of the general presumption in favour of a broad-based and low tax rate system which underlies internationally regarded taxation reforms such as New Zealand's GST.[39]

59. Hence, as a general approximation, the Authority could reduce to one quarter the economic efficiency losses of its residual charge by recovering 50 per cent of the charge from generators (that is, by doubling the size of the base over which the charge is levied). There is no reason to believe that largely domestic based electricity generation companies, as a class, would be more sensitive to substantially fixed charges than consumers as a class, especially trade-focused consumers such as NZAS. Hence, including generators in the allocation of the residual charge would be for the long-term benefit of consumers.

60. Pacific Aluminium raised this issue—the allocation of the residual costs of the existing transmission network to existing generator users—in its 2016 and 2017 submissions.[40] The Authority's response is to answer a different question. The Authority says it is likely most efficient—and therefore for the long-term benefit of consumers—if the charge were applied only to load "since [if the charge applied to generators] new generators would then delay entering until the energy prices they expect to receive would cover the residual charge."[41] However, this is a response to a question as to whether *new* generators should pay the residual charge; the answer provides no insight into why *existing* generators should not pay the residual charge for existing transmission services.

61. The Authority is right to consider whether some generators (such as new generation plant) or some consumers (such as trade-exposed industries) would be more sensitive to a

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[38] For an explanation of why the economic loss is approximately proportional to the square of the tax rate see Creedy, J.(2009), The distortionary costs of taxation, at http://www.victoria.ac.nz/sacl/cagtr/twg/Publications/5-the-distortionary-costs-of-taxation-johncreedy.pdf and also see Creedy, J. (2003), The Excess Burden of Taxation and Why it (Approximately) Quadruples When the Tax Rate Doubles, New Zealand Treasury Working Paper 03/29, pp. 26, at http://www.treasury.govt.nz/publications/research-policy/wp/2003/03-29

[39] See for example, the Report of the Victoria University of Wellington Tax Working Group, 'A Tax System for New Zealand's Future' January 2010.

[40] Pacific Aluminium, (2016), Submission to the Electricity Authority, ibid, page 32, and Pacific Aluminium, (February, 2017), ibid, page 47.

[41] Electricity Authority, (2019) ibid, footnote 330.

substantially fixed charge and should face a reduced residual charge. However, that is not an argument for exempting all existing generators from paying a residual charge for the existing transmission services they utilise. Exempting generators as a class from the fixed residual charge, and imposing those costs on consumers, clearly would not promote the Authority's statutory purpose as it would not be in the long-term interest of consumers.

Prudent discount

62. In developing its prudent discount policy, the Authority references accepted economic theory that any charge should be between incremental and stand-alone cost. However, the Authority no longer proposes that the upper boundary of this test be implemented on the basis of a stand-alone cost, as theory requires and as it proposed in the 2016 Issues Paper and Supplementary Consultation papers. Rather, it now proposes that a prudential discount should be available only where a transmission customer can establish that it would be "technically and operationally feasible, and commercially beneficial" for it to by-pass the grid.[42]

63. In many circumstances, the two approaches would arrive at the same outcome; where it is technically feasible for an entity to by-pass the grid, the cost of that by-pass option would set a ceiling on transmission charges. However, the Authority's revised approach would result in inefficient outcomes where an entity is charged more than the stand-alone cost, but cannot by-pass the grid for other reasons. For example, by-pass might not be legally feasible because resource consent would never be given to build a duplicate transmission corridor through pristine wilderness. In these circumstances, the proposed draft Guideline would expose the transmission customer to paying more than the standalone cost, an outcome at odds with the principles the Authority says underpins its approach.

64. The Authority considers it can derive the principles for regulating prices of a natural monopoly by analogy with the way prices are set in workably competitive markets.[43] The Authority observes that workably competitive markets tend to be reasonably efficient. Hence, if it regulates prices for transmission services on a basis similar to the prices that result from the workings of workably competitive markets those prices should be reasonably efficient.[44]

65. The Authority reasons that:[45]

> *With workable competition, competitive entry and exit ensures that users collectively tend to be charged no more than the full cost of production of the services and that all efficient investments are undertaken. With natural monopolies, we cannot*

[42] Electricity Authority, (2019) ibid, Appendix A, Draft TPM Guidelines, clause 47.
[43] Electricity Authority, (2019) ibid, Appendix D, paragraph D.28.
[44] Op cit, D.28. The Authority finds support for this view in a statement by the High Court in Wellington Airport & others v Commerce Commission. However, the Court was discussing the purpose statement for Part 4 of the Commerce Act which requires the Commission to "promote outcomes that are consistent with outcomes of [workably] competitive markets". The Authority must show that its approach would achieve its statutory objective, not that of the Commerce Commission.
[45] Electricity Authority, (2019) ibid, Appendix D, paragraph D.30.

depend on competition to lead to this outcome. Instead we rely on regulation to pursue the same end.

66. In a workably competitive market, an entity would not be able to exploit a statutory monopoly (in this example, a resource consent for a transmission corridor) to charge more than the standalone cost of a service. To meet the principles it says underpins its approach, and that would achieve its statutory objective, the Authority needs to reintroduce into the proposed prudential discount a provision for the discount to apply so that a transmission customer does not pay more than the standalone costs of the transmission services it receives.

Inconsistent valuation of post-2019 assets

67. The proposed draft TPM Guidelines would recover post-2019 investments using a different valuation method from the method used by the Commerce Commission in setting Transpower's recoverable revenue, with the difference being absorbed by the residual charge.[46] The Authority recognises that adopting a different valuation method will give rise to economic inefficiencies as the residual charge would have to be adjusted over time to allow for the difference between the depreciated historic charges used by Transpower to determine its allowed revenue and the charges calculated using Indexed Historical Cost as proposed by the Authority. A varying residual charge is less efficient than a constant one that generates the same present value of revenue because the inefficiency generated by a tax-like charge increases more than proportionately with the rate of change (this effect was discussed in paragraphs 58 and 59 above).[47]

68. While acknowledging that its approach would give rise to these avoidable inefficiencies, the Authority considers the charges that would result from using Indexed Historical Cost valuation would be more aligned with charges that would emerge if the transmission services were workably competitive. The Authority asserts that the efficiency benefits of "having annual price signals that better reflect the flow of services delivered by the investments" would outweigh the inefficiencies from the varying residual charge.[48]

69. The Authority provides no quantitative or qualitative reasoning to support its statement that the efficiency benefits from pricing new assets using indexed historical cost would exceed the efficiency losses from increasing the residual charge for all other assets. The Authority's conclusion is improbable for three reasons:

    a. The efficiency losses are incurred up front, while the benefits are deferred.

    b. The approach undermines the certainty consumers expected from the Commerce Commission's Input Methodologies.

    c. The approach would result in significant inter-temporal wealth transfers.

[46] Electricity Authority, (2019) ibid, Appendix D, paragraph D.79.
[47] Electricity Authority, (2019) ibid, Appendix D, paragraph B.93.
[48] Electricity Authority, (2019) ibid, Appendix B, paragraph B.95.

70. To help illustrate these points, Rio Tinto reproduces below two figures from the Pacific Aluminium submission on the Authority's 2016 Supplementary Consultation Paper.[49] These figures shows the profile of nominal and real charges under the alternative valuation methods, for one investment, labelled as "new asset A".[50]

Figure 1 Transpower's real annual cashflow from benefits-based charge for new asset A – DHC vs IHC

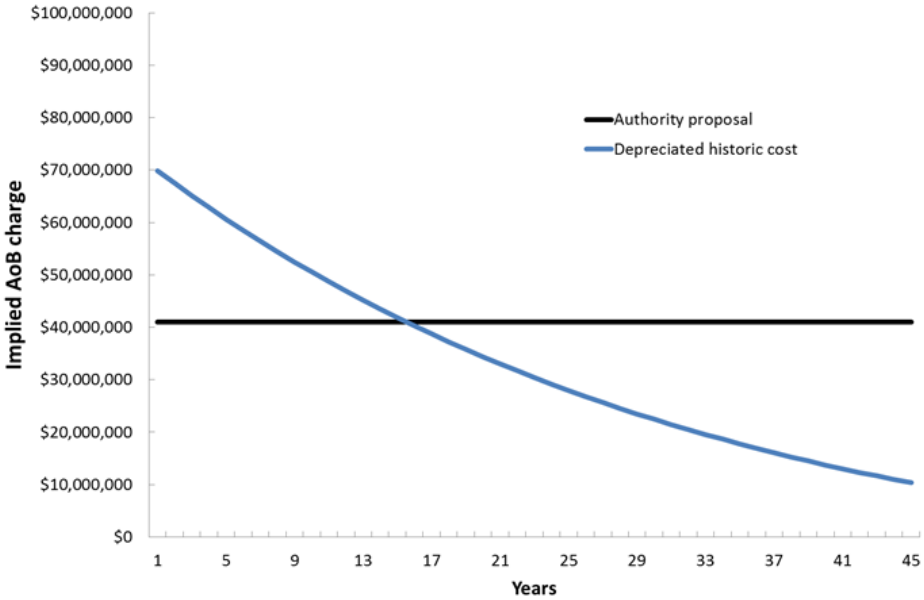
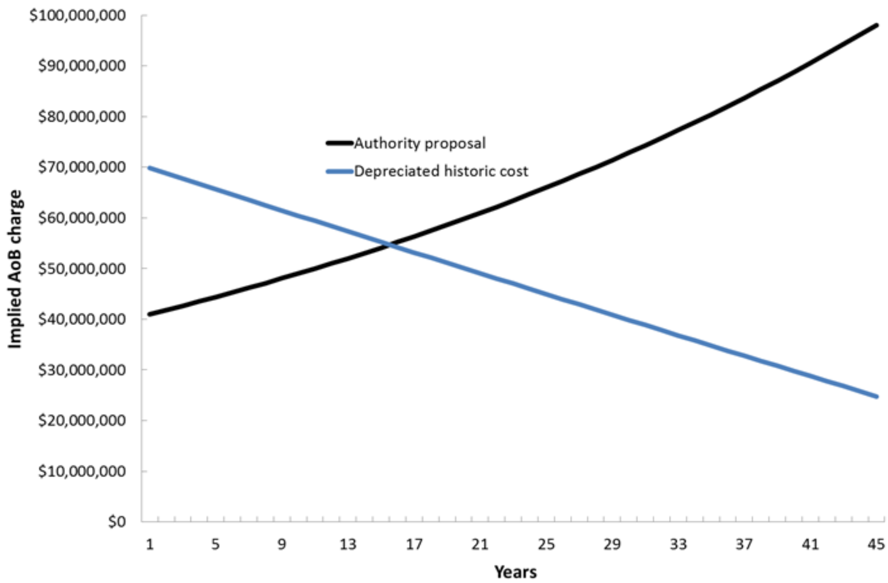


Figure 2 Transpower's nominal annual cashflow from benefits-based charge for new asset A – DHC vs IHC



[49] Pacific Aluminium, (February, 2017), ibid, page 25.

[50] Pacific Aluminium used the cost data from an existing investment, NIGU, to ensure the example was realistic. As the shape of the curves would be same for any new investment of equivalent value, we simply refer to the example as "new asset A". The primary assumptions in the modelling are: capital cost of $876.3 million; operational and maintenance costs of $2 million per annum; depreciation, straight-line, 45 years; inflation, 2% per annum; WACC, 5.58%.

71. The blue curve represents the approved maximum allowable revenue Transpower can recover in each year for the relevant assets, while the black curve represents the amount that could be recovered from a benefits-based charge under the draft Guidelines. As the figures show, substantially less revenue would be earned from the benefits-based charge early in the life of an asset under the Authority's proposal than Transpower would be permitted to recover under its maximum allowable revenue for that asset. This deficit would be recovered through the residual charge, giving rise to the economic inefficiencies that the Authority recognises.

72. There is little reason to believe that benefit-based charges determined on the black line would produce materially better economic efficiencies relative to benefit-based charges determined on the blue line. In either case, the charges would be paid by the entities benefiting from the new services, and those benefits can be expected to exceed the charge (otherwise, the investment should not have been approved). The only difference that occurs, is that a larger proportion of the consumer, or producer (as the case may be), surplus is absorbed by the charges in the initial years if the charge is based on depreciated historic cost valuations. In the later years, these effects may dissipate for some customers benefiting from a mix of new and old assets being recovered and hence for those customers the lines in the charges may tend to converge.

73. Even were the Authority to be right in its deductions over outcomes of workably competitive markets (and the views of the Commerce Commission, New Zealand's expert competition body, were wrong), its proposal does not reflect 'what occurs in workably competitive markets for utility-type services' in all regards. A substantial part of the revenue/charges for transmission services under the Authority's proposal would be recovered through the residual charge, whereas in its hypothetical workably competitive market analogy revenue is determined solely by the charge for the service.[51]

74. Because the Authority's proposal differs from its hypothetical workably competitive market analogy, influences other than the benefits-based charge would impact on the incentives and decisions facing Transpower and transmission customers. Therefore, the Authority cannot reasonably presume that the efficiency characteristics which it deduces from its discussion of workably competitive markets would arise in practice, because the price signals and incentives created by its proposal would differ from those in its hypothetical market. For example, decisions by customers to continue to receive transmission services, and decisions by new entrants to acquire transmission services, would be influenced by the total cost to them of transmission services (benefits-based plus residual charge), not just the benefits-based charge as would be the case in the hypothetical market.

75. The differences between the Authority's proposal and its hypothetical market may also mean that its preferred valuation method is not the best valuation method in practice, even if the Authority is correct in its view of how a workably competitive market would value

[51] The Authority (paragraph B.84) refers to an anology of renting a trailer, without introducing to its analogy the prospect that the trailer renter would also be charged a residual charge that exceeds the rental for the trailer and that residual charge would vary depening upon the timing and quantum of new trailers rented by other users.

utility-type assets. It is well established in the economics literature (theory of second best) that, when any of the conditions jointly necessary for economic efficiency is absent, the next best solution may involve changing other variables from conditions which would otherwise be theoretically optimal; the second-best solution may look starkly different to the first best. Under the Authority's proposal, transmission revenue would not be linked to the prices paid for transmission services as it would in a hypothetical market; therefore the second-best solution conceivably involves valuing assets for pricing on a basis different from a first best solution.

Undermining the certainty consumers expected from the Input Methodologies

76. The Commerce Commission's use of a depreciated historic cost valuation method is now a requirement of its Input Methodologies. These Input Methodologies were developed over several years of extensive consultation with the electricity industry and consumers and confirmed by the High Court on merits appeal. The Input Methodologies have the statutory purpose under Section 52R of the Commerce Act of:

    > *The purpose of input methodologies is to <u>promote certainty for suppliers and consumers</u> in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services under this Part.* (emphasis added)

77. The effect of the Authority's approach would be to undermine the certainty intended for consumers. Transpower would retain the certainty of having its revenue determined according to the valuation method specified in the Input Methodologies—the variance in the residual charge would maintain that certainty for Transpower. However, the charges paid by consumers for new assets would not be determined by the costs established by the Input Methodologies, but by a different methodology substituted by the Authority.

78. The uncertainty for consumers in the charges they face for services regulated under Part 4 of the Commerce Act—uncertainty generated by the Authority's approach—extends beyond the valuation method. If the Authority considers it can substitute its own views on the valuation method, there would seem no reason in principle why it might not substitute its views on other cost elements specified in the Input Methodologies, for example its view of WACC. Following the Authority's own logic, it may come to the view that the Commerce Commission's estimate of WACC does not reflect an outcome of a workably competitive market and substitute a higher or lower WACC (with further adjustments to the residual charge to ensure Transpower benefits from the certainty intended by the Input Methodologies but not consumers).

79. The Authority makes no attempt to reconcile its own statutory obligation to regulate for the long-term benefit of consumers with its undermining of a statutory benefit intended for consumers. If the Authority believes the Commerce Commission erred in its choice of valuation method, it should make its case to the Commerce Commission to review that methodology.

Significant intertemporal wealth transfers

80. As the figures above illustrative, the Authority's approach would give rise to a significant inter-temporal wealth transfer. In the example, approximately $30 million of allowable revenue for "new asset A" would be recovered through charges to other customers in the initial years. This situation gradually reverses over the life of the asset, until year 45 when approximately $73 million (in nominal terms) would be recovered from the "new asset A" benefit-based charge in excess of the maximum allowable revenue attributable to that asset.

81. This inter-temporal transfer is, in aggregate, expected to be neutral over the life of the asset in real terms. However, it is very likely that the customers paying the "new asset A" charge and the residual charge would have changed 45 years after the investment is made. This means that the transfer would not be neutral in terms of its incidence. It would also not be neutral in terms of the incentives created for transmission customers paying the "new asset A" charge and the residual charge in any given year.

82. These incentive and incidence effects are material to assessing the economic efficiency effects of the Authority's proposal, but are not addressed in its 2019 Issues Paper nor in the cost benefit assessment. The Authority does not explain how such (unnecessary) inter-temporal transfers would promote the long-term interest of consumers.

Response to Authority's questions

The Authority lists in Appendix I the questions it asks throughout the 2019 Issues Paper. This section of Rio Tinto's submission responds to those questions, using the question numbers and sequence as set out in Appendix I of the 2019 Issues Paper.

Chapter 2

I.1 Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?

Rio Tinto agrees that the Authority has correctly identified the flaws with the current TPM and that changing the TPM is necessary and urgent as those flaws are leading to inefficient investment and consumption outcomes.

Chapter 3

I.2 What are your overall views on the Authority's proposal for changes to the TPM guidelines?

Rio Tinto continues to support the introduction of benefits-based charges. We agree that those who benefit from specific grid investments should pay for them. We agree with the Authority that benefits-based charging would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives.

However, in developing specific proposals, and especially the charges for existing assets, the Authority fails to apply its own proposed TPM Guidelines and reasoning. The charges specified in Schedule 1 of the draft Guidelines would form a very specific numerical regulation; the modelling undertaken by the Authority to support those regulations is not fit for purpose.

Chapter 4

I.3 Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?

Rio Tinto has not assessed the Authority's quantitative estimates of costs and benefits. We agree that a benefits-based charge would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives. Rio Tinto considers that the methodology underpinning the cost and benefits would be improved by:

- Recognising that the benefits of benefits-based charges, and especially extending the charges to existing assets, are likely materially understated because the Authority moderates the impact of expected price changes to mitigate what would have been benefits to consumers but not generators—see paragraphs 49 to 54 of Rio Tinto's submission.
- Correctly assessing the economic efficiency costs that would result from the Authority's proposal to exempt existing generators from paying the residual charge for existing transmission assets—see paragraphs 57 to 61 of Rio Tinto's submission.
- Properly assessing the economic costs, especially the uncertainty to consumers, that would be introduced unnecessarily by using a different valuation method for post-2019 assets from

that applied by the Commerce Commission in determining the cost of those assets—see paragraphs 67 to 81 of Rio Tinto's submission.

I.4 Do you have any comments on the matters covered in chapter 4?

The cost benefit analysis does not address the matters described in response to Question I.3 above.

Chapter 5

Refer Questions I66-I67.

The Authority's questions under chapter 6 do not focus on the issues that arise from chapter 5. The charges specified in Schedule 1 of the draft Guidelines would form a very specific numerical regulation. However, those charges were not calculated by applying the concepts and principles set out in the 2019 Issues Paper. The choices by the Authority to not carry forward negative benefits, to apply reduced (and possibly varying) values for reliability, and its selection of modelling years, are in effect manual adjustments by the Authority that reallocate large sums of money between transmission customers. In the absence of a robust explanation, these adjustments risk the impression the Authority was solving for a pre-determined, and undisclosed, outcome. In addition, the modelling that determines these charges does not reflect the realities of the New Zealand transmission grid and hence the benefits it provides. See paragraphs 12 to 48 of Rio Tinto's submission.

Chapter 6

I.5 How long should Transpower have to complete its development of the TPM and why?

The Authority's proposal that Transpower should have four years to implement the TPM is far too long. The Authority's discussion about why it would take Transpower 18 months to propose a new TPM, and 13 months to implement it, is far from compelling. The Authority has also declined to comment on why it would take 8 months for the Authority to approve and integrate the TPM into the Code. There is also suggestion that this extremely slow process could be delayed another year.

Given the decade that Authority has spent considering the TPM (and Transpower having been engaged over that whole period), and the Authority's finding that the economic costs of the existing flaws are compounding, it is not reasonable that it should take Transpower 18 months to make sense of the Authority's guidelines. The Authority should allow no more than 12 months for Transpower to propose the TPM.

It is also not reasonable to allow Transpower 13 months to implement the TPM. The Authority is proposing to include a checkpoint process on Transpower's TPM development process. The benefit of adding a checkpoint process is that Transpower should be held to accept that it has little risk from implementing the TPM as it will be checked during development. The expectation should be that the checkpoint process would significantly reduce the implementation time. Recognising this time saving, along with a reduction in Transpower's proposal development time, a more reasonable time for the Authority's consideration and approval time and reducing the slack period before the November notification of prices, would allow two years to be cut from the timetable.

The Authority should set 1 April 2022 as the date for applying the new TPM prices.

I.6 What checkpoints (if any) should the Authority set in the TPM development process?

The purpose of the checkpoints would be to ensure that Transpower makes timely progress in the development of the TPM and eliminate the risk that Transpower develops a TPM proposal that would not be approved by the Authority. This reduction in risk should flow through to significantly reduced approval and implementation time periods. In the past, Transpower has opposed various aspects of the Authority's approach to the TPM Guidelines and, if it is consistent, can be expected to continue to do so. Transpower could experience difficulty making decisions about aspects of the TPM it does not support. Therefore, without a rigorous program of checkpoints there is the risk of the TPM development process becoming bogged down and delayed.

Rio Tinto supports including checkpoints and, commensurately, setting the date when the new prices are to be in effect.

I.7 How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?

The best way for Transpower to engage with stakeholders would be to put an obligation on it to consult through development of the TPM and to give effect to new TPM prices by 1 April 2022. This will give Transpower strong incentives to engage meaningfully with stakeholders.

I.8 In addition to the specific questions above, do you have any further comments on the matters covered in chapter 6?

The Authority has made its task more difficult through delay—if it had designed and implemented a benefits-based charge within a reasonable period for its decision-making many of the now pre-2019 investments would still have been prospective. The Authority's delays have been costly, for NZAS and for the economy overall. Given the compounding nature of these costs, the Authority should do all it can to expedite its decision-making.

Appendix A

I.9 What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?

Elements of pricing proposals as reflected in the draft "Proposed TPM Guidelines" contain serious flaws and inconsistencies. As explained in Rio Tinto's submission, these flaws and inconsistencies are due to the Authority:

a. Failing to apply its own proposed TPM Guidelines and reasoning in specifying charges for specific investments completed prior to 2019.
b. Misreading its statutory purpose statement as it applies to rules that transfer wealth between different transmission customers.
c. Not specifying a Prudent Discount Policy that would achieve its intended purpose.
d. Applying a different valuation method to setting the prices for post-2019 assets than the Commerce Commission applies in setting allowable revenue.

Appendix B
General matters

I.10 Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?

These general provisions are undermined by the Authority's prescription in the following provisions that would:

- Fail to apply the Authority's own proposed TPM Guidelines and reasoning in specifying charges for specific investments completed prior to 2019.
- Transfer wealth between different transmission customers.
- Not specifying a Prudent Discount Policy that avoids any transmission customer paying more than the standalone cost of transmission services it receives.
- Exempt existing generators from paying the residual charge associated with existing transmission assets.
- Apply a different valuation method to setting the prices for post-2019 assets than the Commerce Commission applies in setting allowable revenue.

Connection charge

I.11 Should the current guidelines on connection charges be largely retained or are changes required?

Rio Tinto supports retaining the current guidelines for connection charges.

I.12 Should first-mover disadvantage be addressed in the TPM, and if so, how?

The problem of 'first mover disadvantage' is created by the Authority not including all pre-2019 assets in its benefits-based charge. If all transmission customers paid for the services they receive, and hence there was no residual charge, there would be no problem of first-mover disadvantage as all subsequent transmission customers would also pay for the services they receive.

Benefit-based charge

I.13 Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?

Rio Tinto supports the introduction of benefits-based charges. We agree that those who benefit from specific grid investments should pay for them. We agree with the Authority that benefits-based charging would send better signals to consumers about the economic costs of using the grid and investing in grid-connected generation and transmission alternatives.

I.14 Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?

The costs of all pre-2019 investments should be recovered through a benefits-based charge. The economic efficiency arguments for applying a benefits-based charge to existing assets are just as strong as the arguments for applying the charge to new investments, for the reasons now identified by the Authority (see the literature cited by the Authority at footnote 322 of its 2019 Issues Paper).

I.15 Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?

The costs of all pre-2019 investments should be recovered through a benefits-based charge. The failure of the Authority to identify benefits is a failure in its modelling, not a reflection that the existing transmission grid does not provide benefits—see paragraphs 13 to 45 of Rio Tinto's submission.

I.16 How should the covered cost of the investment be defined?

The relevant costs are the costs that the Commerce Commission has determined that Transpower may recover through its regulated revenue.

I.17 How should the covered cost of a benefit-based investment be recovered over time for

pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?

Transpower should be required to determine costs of pre-2019 and post-2019 methods by applying the same methodology as specified by the Commerce Commission for establishing the costs Transpower may recover through its regulated revenue—see paragraphs 67 to 82 of Rio Tinto's submission.

I.18 Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?

A net load approach would provide the better economic signals for efficient choices between transmission and transmission alternatives, though there should be consistency in approach with the ACOT mechanism.

I.19 Should the guidelines distinguish between high-value and low-value investments?

An approach that distinguishes between high-value and low-value investments in terms of the degree of specificity of the benefits is likely to be pragmatic and sensible. However, the Authority should bear in mind the very substantial economic efficiency gains expected from benefits-based charging and that the costs of extending the benefits-based charge (to low-value and to pre-2019 investments) is likely to be tiny in comparison to the expected benefits.

I.20 If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?

The costs of low-value investments should be allocated via the benefit-based charge because of the economic efficiency gains from doing so.

I.21 What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?

Rio Tinto agrees with aligning the threshold with the Commerce Commission's threshold for 'major capex'. This would, as the Authority notes, allow Transpower to rely on information produced for the Commerce Commission's investment test.

I.22 What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?

Rio Tinto supports extending the benefits-charge to the seven major existing investments (and to other pre-2019 investments). However the Authority should apply its own draft Guidelines and reasoning to the calculation of these charges, which it has not done in the 2019 Issues paper proposals—see paragraphs 7 to 48 of Rio Tinto's submission.

I.23 How should the costs of the investments that are not covered by the benefit-based charge be allocated?

Rio Tinto supports the concept of a residual charge that does not distort incentives to invest or use the grid to recover transmission costs that cannot be recovered by a benefits-based charge. However, any such residual charge should be kept to a minimum and the combined residual charge and benefits-based charge should not exceed the standalone cost of the transmission services received by a transmission customer.

I.24 Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?

It is unrealistic to believe that charges can be determined once and not revised in response to a substantial and sustained change in grid use. The Code (clause 12.86) already provides for the TPM to be revised if there is a material change in circumstances.

I.25 Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?

No, the implementation of benefit-based charges should not be further deferred. As the Authority observes, the economic efficiency costs of the existing TPM are compounding. The administrative costs of extending the benefits-based charge to low-value and to pre-2019 investments is likely to be tiny in comparison to the expected benefits.

I.26 Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?

No, there should be no reassignment. A reassignment would create incentives for entities to overstate expected benefits of transmission investment proposals knowing that the costs would be transferred on to others and risk similar outcomes to that which arises from the Authority's modelling of the lower South Island renewables investment (where it proposes to allocate the costs to parties other than those identified as beneficiaries in the investment proposal).

Residual charge

I.27 Should the guidelines provide for a single residual charge or multiple residual charges?

There should be a single residual charge applying to both existing generators and existing load customers. However, the charge should be itemised so that customers can identify what they pay for under different categories of cost such as, based on the Authority's current proposal:

- Payments for large pre-2019 investments whose benefits do not exceed the costs, such as the NIGU.
- Payments for subsidies to cap the payments of other customers.
- Payments for new investments where the inconsistency between the Commerce Commission's approach to determining revenue and the TPM's approach to charging beneficiaries for that asset results in an under-recovery which must be charged for through the residual.

This level of transparency will assist the Authority and customers to assess the effectiveness of the revised TPM over time and inform the debate on regulatory reform, such as consideration of whether additional pre-2019 assets should be charged to beneficiaries rather than through the residual charge, as allowed for in the draft guidelines.

I.28 Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?

The residual MAR should be minimal. However, any residual charges should be allocated in a way that minimises distortions and is substantially unavoidable. Fixed charges based on historical load and generation capacity could meet these criteria if designed correctly.

I.29 Should the residual charge be allocated based on AMD, annual consumption, a mixed

approach, or some other approach?

The Authority has answered its own questions with regards to the residual charges. They must be allocated in the least distortionary, non-avoidable way. In this regard the Authority has correctly identified that, among all counterparties, residual charges on industrial consumers are both distortionary (through incentivising inefficient exit) and avoidable (again through inefficient exit).

The Authority's proposal that gross AMD charges will most likely allocate charges to those that are least likely to take short or long term action to avoid them is correct. Although a charge based on gross AMD reduces distortions for industrial consumers, there is still the risk of inefficient exit.

I.30 If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?

Charges that gross up the AMD demand of customers is least likely to be avoidable and creates the smallest distortions.

I.31 Should demand be measured using a net load or gross load approach for the allocation of the residual charge?

See answer to question I.30.

I.32 If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?

See answer to question I.30.

I.33 Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?

Rio Tinto supports using data from the Reconciliation Manager given the protocols for insuring the accuracy of that data.

I.34 Should the Authority determine the initial allocation of the residual charge in advance as a default or required allocation in the guidelines?

The Authority has demonstrated that it does not have the discipline or expertise to follow its own guidelines in calculating charges and should not assume the responsibility to do so—see paragraphs 7 to 48 of Rio Tinto's submission

I.35 Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?

Rio Tinto agrees that it would be unfair for distribution customers to pick up residual charges if a large consumer exits from their network. However, this equitable treatment is only possible within distribution networks. If a direct connect customer were to exit, then increased charges will flow though to other consumers regardless of any equity concerns.

I.36 Should the residual charge apply to both generation and load customers, or only to load customers?

Residual charges should apply to both generation and load customers. We agree that residual charges are both distortionary and avoidable if charged to generators as a peak charge or a consumption charge. We do not agree that this applies if generator's charges are fixed. In most periods the electricity market will clear on short-run variable costs. Fixed charges will not be recoverable. During periods of local or global scarcity generators will have some ability to recover fixed costs and there would be some distortion of scarcity prices (if prices in such circumstances are linked to costs). However, this is offset by reducing the distortionary price effects on loads generally, and reducing the incentives to avoid the residual charge, by allocating the residual across a broader base. See paragraphs 57 to 61 of Rio Tinto's submission.

Other

I.37 Are the proposed provisions relating to adjustments appropriate?

The Authority's analysis in relation to adjustments is partial and incomplete. As discussed in paragraphs 59 to 61, the Authority considers the potential production efficiency loss from a new entrant avoiding charges levied on existing entities, but not the allocative efficiency loses of exempting all generators from residual charges. The solution for the Authority is to minimise the residual charge by including all existing assets in the benefits-based charge, using the same basis for calculating cost as used by the Commission in setting the revenue charge, and then recovering that minimal residual charge from the broadest base feasible.

I.38 Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?

To achieve the intended efficiency benefits, the prudent discount should apply for the life of the relevant asset (because the by-pass option may exist for the life of the relevant assets).

I.39 Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?

No. There is no support in the purpose statement for the Authority to require some commercial customers to subsidise other commercial customers. See paragraphs 55 to 56 of Rio Tinto's submission.

I.40 Should the price cap be specified as a percentage of electricity bills or in some other way?

There should not be a price cap. See paragraphs 55 to 56 of Rio Tinto's submission.

I.41 Should the price cap apply only to load customers, or to generators as well?

There should not be a price cap. See paragraphs 55 to 56 of Rio Tinto's submission.

I.42 How should the price cap be funded?

There should not be a price cap. See paragraphs 55 to 56 of Rio Tinto's submission.

I.43 Are the proposed additional components appropriate? If not, what changes should be made?

After nearly a decade of developing its TPM proposal, the Authority should be in a position to specify the components of the TPM. The Code provides for the Authority to initiative a further review if there is subsequently a material change in circumstances.

I.44 Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?

Rio Tinto agrees with the Authority in recognising the role of nodal prices in signalling efficient marginal costs, and hence additional peak charges or Long Run Marginal Cost (LRMC) based charges are unnecessary. Rio Tinto agrees with this analysis, for the reasons set out in Pacific Aluminium's submission on the Authority's Second Issues Paper.[52]

I.45 Should the peak charge be applied only where the grid would otherwise be congested?

See answer to question I.44 above.

I.46 Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?

See answer to question I.44 above.

I.47 Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?

Yes. The economic efficiency arguments for applying a benefits-based charge to existing assets are just as strong as the arguments for applying the charge to new investments, for the reasons now identified by the Authority (see the literature cited by the Authority at footnote 322 of its 2019 Issues Paper).

Without an inducement to do so, Transpower is unlikely to propose future changes to the TPM to apply a benefits-based charge to additional pre-2019 assets since it has no incentive to do so. Therefore, the TPM needs to define specific triggers to require Transpower to review relevant assets and criteria to apply in determining whether a benefits-based charge should apply.

I.48 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?

See Rio Tinto's submission for its comments on the 2019 Issues Paper.

Appendix C

I.49 Do you have any comments on the matters covered in this appendix C?

Rio Tinto agrees that there has been a material change in circumstances, for the reasons set out by the Authority in its appendix C.

Appendix D

I.50 Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?

Rio Tinto continues to support a move toward cost-reflective and service-based pricing.

I.51 Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?

No. Intuitive, or appreciative, reasoning of the nature undertaken by the Authority can provide useful insights for policy development, but is not a solid basis for choosing one pricing approach over another. See paragraphs 73 to 82 of Rio Tinto's submission.

I.52 Do you agree with the conclusions of appendix D?

[52] Pacific Aluminium, (2016), Submission to the Electricity Authority, ibid, pages 13 – 15.

Rio Tinto strongly disagrees with some of the conclusions in appendix D, notably:

- The proposal to apply a different valuation method to setting the prices for post-2019 assets than the Commerce Commission applies in setting allowable revenue—see paragraphs 67 to 82 of Rio Tinto's submission.
- The proposal to exempt existing generators from the residual charge--see paragraphs 57 to 61 of Rio Tinto's submission.

I.53 Do you have any comments on the matters covered in this appendix D?

Yes, see Rio Tinto's submission.

Appendix E

I.54 Do you agree with the conclusions we draw from Transpower's report *The role of peak pricing for transmission*?

Yes. Rio Tinto agrees with the Authority in recognising the role of nodal prices in signalling efficient marginal costs, and hence additional peak charges or Long Run Marginal Cost (LRMC) based charges are unnecessary. Rio Tinto agrees with this analysis, for the reasons set out in Pacific Aluminium's submission on the Authority's Second Issues Paper.[53]

I.55 Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?

Yes.

I.56 Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?

Yes.

I.57 Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?

Yes.

I.58 Do you agree that it would not be efficient to provide for a permanent peak based charge in addition to nodal prices?

Yes.

I.59 Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?

Yes. No.

I.60 Do you have any comments on the matters covered in this appendix E?

No.

Appendix F

[53] Pacific Aluminium, (2016), Submission to the Electricity Authority, ibid, pages 13 – 15.

Rio Tinto does not express a view on the matters discussed in Appendix F.

I.61 Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?

I.62 Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be efficient?

I.63 Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?

I.64 In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?

Appendix G

I.65 Do you have any comments on the matters covered in this appendix G?

Rio Tinto broadly agrees with the Authority's response to criticisms of its reasoning in support of benefit-based charges. The arguments presented by the Authority in Appendix G echo the submissions by NZAS on the 2016 Issues Paper. However, Rio Tinto does not agree with the Authority's conclusion that it was not able to identify net benefits for three investments. As set out in Rio Tinto's submission, the Authority's approach considered only a small subset of possible benefits (competition benefits) and did not assess the reliability benefits of investments that were undertaken for reliability reasons—see paragraphs 7 to 48 of Rio Tinto's submission.

Appendix H

Questions I.66 to I.70.

The questions identified by the Authority are not adequate to allow a response to the inadequacies in the Authority's modelling and proposed benefit allocation. The charges specified in Schedule 1 of the draft Guidelines would form a very specific numerical regulation; the modelling undertaken by the Authority to support those regulations is not fit for purpose—see paragraphs 7 to 48 of Rio Tinto's submission.