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3 March 2020

Northpower

Supplementary Consultation Paper Transmission Pricing Methodology

March 2020

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1. Introduction

Northpower Limited (Northpower) welcomes the opportunity to respond to the Electricity Authority's (the Authority's) Supplementary consultation paper on its proposed reforms to the Transmission Pricing Methodology (TPM).[1] No aspect of this submission is confidential. We are also a member of the TPM Group and endorse its submission.

The Authority's Supplementary consultation paper appears to be suggesting that it will round-out its TPM review by:[2]

- considering first the four very narrow 'second-tier' issues broached in the Supplementary consultation paper; then
- undertaking a relatively perfunctory consultation on its much-maligned cost-benefit analysis (CBA) and peak charges.

Assuming we have interpreted this correctly,[3] the process strikes us as inadequate and antithetical to sound regulatory practice, especially given the large volume of other 'big ticket' items that remain unsettled. In addition to this major overarching problem there are several deficiencies with the four specific measures proposed in the paper. Most notably:

- the mooted revisions to the prudent discount policy (PDP) are inconsistent with basic economic principles, unworkable, unfair and unnecessary; and
- the proposal to apply a depreciated historical cost (DHC) methodology to all investments earmarked for benefits-based (BB) charges would produce an inefficient time profile of prices that would discourage/encourage consumption at precisely the wrong times.

We elaborate on these points in the remainder of this submission. Should you have any questions about any aspect of this document feel free to contact either **Andrew McLeod**, Chief Executive (09 983 0917 or andrew.mcleod@northpower.com) or **Josie Boyd**, GM Network (022 244 4409 or josie.boyd@northpower.com).

2. Overarching process issues

Northpower is concerned by the manner in which the Authority is proposing to close-out its TPM review. It seems diametrically at odds with best regulatory practice to be focussing on four technical design issues of comparatively minor importance at a time when so many crucial foundational matters remain unresolved.[4] It is also unclear when – or even *if* – the Authority intends to address those crucial outstanding problems.

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1. Electricity Authority, *Transmission pricing methodology: 2019 Issues paper, Supplementary consultation, Consultation paper,* 11 February 2020 (hereafter: "Supplementary consultation paper").

2. In its *Market Brief* of 11 February, the Authority stated that it: "intends to publish further papers in early March. The papers will cover the Authority's consideration of submissions on the cost benefit analysis (CBA), including updated CBA code and tables, and peak charging."

3. For example, it could be – and hopefully is – the case that the Authority's March consultation materials cover far more matters than just the CBA and peak charging.

4. For example, when implementing new regulatory arrangements, the Commerce Commission always leaves its 'technical implementation/drafting' paper until the very end of its consultation process, after the elementary foundations of the framework have been locked in place.

2.1 Unresolved overarching issues

Several parties have called into question the essential economic underpinnings of the Authority's proposal. Northpower concluded that:[5]

> *"…the proposal* ***fails to meet the three most basic criteria of regulatory best practice*** *… it would not be addressing a* ***material and enduring problem*** *… the proposal clearly does not represent* ***the smallest intervention possible*** *and it is not based on* ***robust economic foundations*** *or a* ***sound CBA****… the Authority has not addressed satisfactorily the plethora of criticisms that were levelled at largely the same methodology during the previous consultation round. There is consequently* ***no reason to be confident that it would be a more efficient, equitable and durable methodology****. The proposal also appears to be at odds with many other crucial energy market policies, such as* ***climate change objectives and energy efficiency goals****. In short, it* ***does not represent a solid foundation for change****."*

Axiom Economics – an expert advisor to Transpower – observed similarly that:[6]

> *"… like its predecessors,* ***we do not consider that the latest proposal has a robust economic foundation****. There is no reason to think that it would provide more efficient forward-looking price signals or result in a superior allocation of sunk costs. Rather, the proposed approach is more likely to compromise significantly both static and dynamic efficiency."* [our emphasis]

Transpower itself – a party that is largely financially ambivalent to any changes to the TPM – has stated likewise that:[7]

> *"…the Authority's current TPM proposal* ***runs a risk of not being in consumers' best interests and may not meet the Authority's statutory objective*** *of delivering significant long-term benefits to consumers. Moreover, we are concerned that the proposal may not support New Zealand's transition to a low-emissions economy."* [our emphasis]

These conclusions were effectively inescapable considering the large number of serious theoretical and practical problems that were identified with the Authority's proposal during the previous round of submissions. These included, but were by no means limited to:[8]

- the irreconcilably contradictory rationales offered by the Authority for the centrepiece of its proposal; namely, the benefits-based (BB) charge:[9]
  - on the one hand, the Authority has claimed that it would send an efficient *ex-ante* price signal to customers to alter their behaviour to defer investments; whereas
  - on the other, it has maintained that nodal prices would provide all the signals that customers would need to see to make efficient decisions; and
  - by definition, these things cannot both be true and, in reality, *neither* of them is, which results in a proposal that is incoherent and inconsistent with core economic principles;

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5 Northpower, *2019 Issues Paper Transmission Pricing Review,* 1 October 2019, pp.2 and 4.

6 Axiom Economics, *Economic review of transmission pricing review consultation paper A report for Transpower*, September 2019, p.78.

7 Transpower, *Submission: Transmission pricing review 2019 issues paper*, 1 October 2019, p.1.

8 These overarching problems were set out in detail in Northpower's submission in response to the Authority's Third Issues Paper.

9 This was referred to earlier in the consultation process as an "Area of Benefit charge".

- the proposal to apply those BB charges to a relatively arbitrary subset of existing interconnection (and HVDC) investments, despite the absence of any persuasive economic or equity-based rationale for doing so;
- the adverse impact the proposal may have on New Zealand's ability to meet its various climate change and energy efficiency objectives, i.e., if implemented the reform would – quite deliberately – spur increases in consumption during peak periods; and
- the sheer unworkability of the proposal, i.e., the arrangements would not be durable – they would instead be a perfect recipe for ongoing controversy and conflict amongst stakeholders, Transpower and the Authority.

It is unclear at present when – or even *if* – the Authority intends to grapple with these outstanding issues.[10] Naturally, until it does, it will not have provided a convincing or coherent explanation for why its sweeping, globally unprecedented proposal would lead to superior outcomes for New Zealand's electricity customers.

The Authority is also yet to broach – or even mention – the more modest reform proposals put forward by the likes of the Lantau Group[11] (on behalf of the TPM Group) and Transpower.[12] This is especially disheartening considering the good-faith efforts those parties invested in proposing those options as constructive compromises. It would be unsatisfactory and set an unwelcome precedent for future engagements if those submissions were to just be disregarded without consideration.

2.2 Unresolved detailed design issues

It is also not apparent why – or how – the Authority decided to focus on the four specific matters that it has in its Supplementary consultation paper. Submitters identified a range of other granular design and implementation problems that are yet to be addressed or acknowledged in any fashion. These included (but were not limited to):

- methodological shortcomings in the vSPD modelling used to allocate charges for existing interconnection and HVDC assets assigned for BB charges; for example the methodology clearly does not account properly for reliability and security benefits, i.e., it is plainly illogical to suggest – as the Authority has – that the North Auckland and Northland (NAaN) grid upgrade delivered no benefits from 2014-2018;
- the limitations of the proposed transitional price cap which, as it stands, would provide customers with almost no protection at all against price shocks;
- the practical problems that have been highlighted with the various 'trigger' mechanisms the Authority has suggested for revisiting and reallocating charges; and
- the proposal requires Transpower to 'provide a process' for applying BB charges to large customers who 'enter' or expand significantly after an investment has been made, yet no guidance has been provided about how this could be done without creating distortions.

The Authority appears to have made no explicit accommodations in the remainder of its consultation calendar to consider further this range of issues, which is disconcerting. The

[10] As we mentioned earlier, unless we have misinterpreted the Authority's intentions, the next step in the proposed process appears to involve consultation on just the CBA and peak charging.

[11] The Lantau Group, *Review of Transmission Pricing Guidelines Issues Paper 2019*, 1 October 2019, pp.7-8.

[12] Transpower, *Submission: Transmission pricing review 2019 issues paper*, 1 October 2019, pp.12-13.

detailed design problems raised by various submitters cast further considerable doubt on the efficiency, fairness and durability of the proposed arrangements.

In addition to these crucial overarching procedural problems there are several deficiencies with the specific measures proposed in the Supplementary consultation paper, which we examine in turn below.

3. Prudent discount regime

Northpower is very concerned about the Authority's proposed revisions to the PDP. In our opinion, they are inconsistent with basic economic principles, unworkable, unfair and unnecessary. Further, with all due respect, the Authority is not the appropriate body to be addressing the concern underlying this particular modification. We would consequently encourage the Authority to abandon this aspect of its proposal.

3.1 The logic of the existing PDP

Presently, the PDP is intended to address situations in which the TPM provides parties with incentives to act in ways that are privately beneficial, but inefficient overall. For example, it may sometimes be financially advantageous for a customer to bypass the transmission grid in order to avoid charges. The PDP allows Transpower to grant a discount in such circumstances. To qualify for a prudent discount a customer must demonstrate two things:

- that it has a viable – and *real* – by-pass option that can be implemented in practice, i.e., without a concrete business case grounded in reality the threat of bypass – and the attendant adverse financial effect on other customers – is entirely illusory; and
- that the cost of implementing that option (the 'standalone cost') is less than what the customers would face if it remained connected to the interconnected grid and continued to pay transmission charges via the TPM.

This makes sense since, otherwise, the customer would 'stand-alone' and impose needless price increases on others. However, the Authority is proposing to relax these criteria by allowing customers to apply for prudent discounts on the basis of purely *hypothetical* business cases. Unlike the existing arrangements, this proposed extension makes no sense at all.

3.2 The Authority's objective

The scenario that is clearly 'top of the Authority's mind' is the smelter building a proprietary transmission line from Tiwai Point to Manapouri. In truth, the business could not undertake such an investment because it would not obtain the necessary resource consents. The Authority is suggesting that the PDP should overlook this practical reality and permit the smelter nevertheless to:

- present a *hypothetical* business case for building a duplicate proprietary transmission link from Manapouri on the assumption that it *could* obtain the requisite resource consents (which of course, in the *real world*, it could not); and
- demonstrate that the cost of implementing that option (a purely *fictional* measure of 'standalone cost' with *no basis in fact*) is less than what it would pay if it remained connected to the interconnected transmission grid.

The Authority has described its proposed reform as "limiting transmission charges to efficient standalone cost".[13] However, the existing PDP serves *already* to cap transmission charges at efficient standalone costs. As we have just seen, if a customer's transmission charges exceed its *true* (i.e., *actual, real world*) standalone costs then it will 'stand-alone' unless it is provided with a discount. The regime therefore *already addresses* the risk of inefficient by-pass arising from prices exceeding standalone costs.

Indeed, the Authority *itself* has acknowledged that the purpose of the proposed reform is *not* to prevent inefficient by-pass where a customer has an alternative source of supply.[14]. So, what *is* the rationale for the proposal? As the Authority explains in its paper, the measure is supposedly targeted at stopping disconnections when a customer has no real alternative but to *exit the country* (here again, the Authority clearly has the smelter in mind).[15] In our opinion, that reasoning is badly misguided and would lead to considerable problems.

3.3 The proposal is unprincipled and potentially infeasible

If the Authority's objective is to stop customers from exiting a market 'inefficiently' (which, as we explain below, is arguably beyond its mandate) it makes no sense to offer prudent discounts based on purely fictional measures of stand-alone costs. Those hypothetical cost thresholds will have no direct bearing on firms' exit decisions. Consider an obvious live example: the personnel performing Rio Tinto's ongoing 'strategic review' will not at any stage be examining the hypothetical cost of building a link from Tiwai Point to Manapouri and factoring that metric into the 'stay/go' decision. It is simply not germane to that financial calculus.

Logically, if the goal is to prevent 'inefficient' departures (which, again, is not the Authority's role) then, as a matter of basic economics, any discount should be set at the level needed to prevent a party from departing – no more; no less. But that assessment would not be informed at any stage by the fictional cost of a hypothetical alternative source of supply. It follows that, by definition, any 'prudent discount' calculated using the Authority's proposed approach would be either:

- **too high**, i.e., more than a business needs to remain in the market (it might not need *any* discount), thereby needlessly, inefficiently increasing prices for all other customers; or
- **too low**, i.e., not enough to render the business economically viable, in which case it will still exit the market and the arrangement would have achieved nothing whatsoever.

In other words, the proposed approach would not produce the right number/discount. Moreover, the Authority is unambiguously not in a position to implement the methodology that would deliver the appropriate discount in any particular circumstance. Indeed, when it proposed to perform precisely this role in its 2nd Issues Paper in 2016 (i.e., to calculate the appropriate discount needed to prevent a party from exiting a market inefficiently) submitters rightly pointed out – and the Authority largely accepted – that:

13 Supplementary consultation paper, p.16.

14 After all, the business cases in question would be *hypothetical*, e.g., the smelter is *not* actually going to build a link from Manapouri.

15 Supplementary consultation paper, p.17.

- neither Transpower nor the Authority possessed the industry-specific knowledge that would be needed to make the required assessments about the ongoing financial viability of a business operating in, say, the global aluminium sector; and
- these were therefore ultimately matters best left for central Government, since it can take into account broader macroeconomic factors (e.g., regional employment impacts) when determining cases for subsidies and bring in industry-specific expertise.

Having acknowledged back in 2016 that it was *not* equipped to perform the *relevant* assessment, the Authority is now proposing to perform an assessment that *is* within its sphere of expertise but is wholly *irrelevant* to the question at hand.

In addition, the proposal could prove impossible to implement in *practice*. The Authority seems to have focussed on the smelter's circumstances without considering the broader implications. For example, it has indicated that it might be permissible to assume that the smelter could obtain a resource consent for a line from Tiwai Point to Manapouri. But what other fictional scenarios might be allowable? For example, would it be permissible to imagine that a large customer could embed, say, a geothermal generation unit even if it could not obtain a resource consent?

The EA has not presented any robust basis for distinguishing between acceptable and unacceptable 'fictions' in its Supplementary consultation paper. Herein lies the chief practical problem associated with departing from the real world and straying into the hypothetical. There are seldom any 'black-and-white' answers to the questions one inevitably encounters and, before too long, these experiments can become so divorced from reality that they are unworkable. In our opinion, the Authority's proposal would be likely suffer this familiar problem.

3.4 The proposal is inequitable and could have unintended consequences

For the reasons set out above, there appears to be no sound efficiency grounds for the proposed revisions to the PDP. Yet, for whatever reason, throughout its TPM review the Authority has seemed intent on engineering a price reduction for certain customers including, in particular, the Tiwai Point smelter. This has perhaps been motivated in part – possibly even in the main – by the perceived *unfairness* of the transmission charges that the smelter is paying currently.

However, as many parties have point out, equity is an inherently subjective concept. As far as the smelter is concerned, although it might seem 'fair' to some (including perhaps the Authority) for its transmission bill to go down (through a 'prudent discount' or otherwise), many others – Northpower included – have also highlighted that:

- although the smelter's transmission charges might be 'high', it also pays the lowest wholesale prices in the country – by a very comfortable margin – which serves to increase the prices paid by all other customers; and
- the smelter has received tens of millions of dollars in government subsidies in the past – all funded ultimately by New Zealand taxpayers, including Northland's electricity customers (many of which are low income households).

Furthermore, if the smelter was to receive a discount via the proposed amendment that would mean that the transmission charges paid by all other customers would need to increase to make up the difference. For example, it would result in further wealth transfers from smaller electricity customers at a time when the country is facing widely recognised challenges with energy poverty and affordability. Many – perhaps most – people would view that as inequitable. Large direct-connect customers would also see their charges increase, which may give rise to perverse outcomes and further inequities.

For example, there may be other large customers in positions analogous to the smelter that may be pushed closer to, or past, the point of exit because of any such redistributions. This is not merely hypothetical. Many businesses in Northland are already feeling acutely the financial ramifications of the Coronavirus outbreak. Carter Holt Harvey has announced (see: here) that it will be closing its Whangarei sawmill in April (which employs 111 people) and many other export businesses are experiencing considerable economic distress due to plummeting Chinese demand.

Those businesses would all see their prices go up if the smelter receives a discount but will be unlikely to be in a position to apply for price relief themselves. Specifically, they may not be able to produce a business case illustrating a hypothetical by-pass option that is cheaper than a fictional measure of stand-alone cost. Their broader circumstances may be otherwise *largely indistinguishable* from those currently confronting the smelter – but only some (and perhaps none) of them would receive a discount. Such arbitrariness would be manifestly unfair.

If the proposal is implemented, it is therefore possible that the smelter would receive a discount but still eventually exit (i.e., because the discount is the 'wrong number' for the reasons set out above) and, in the meantime, other large customers may be pushed out of their respective markets due to the resulting price increases. That would clearly be highly undesirable. To that end, we would entreat the Authority to be mindful of what it said in its discussion paper on potential hedge market enhancements released in November last year. In opining on what a successful regulatory intervention looks like, it remarked that:[16]

> *"In principle, **we prefer options with a low level of regulatory intervention**. This is for several reasons, including because **less intervention results in less risk of unintended consequences** … Some options carry greater implementation risk than others, and **we prefer options that present lower risk**. Implementation risk includes such things as whether the option will take a long time and be costly to implement, and **the likelihood of unforeseen barriers to implementation**. For example, if an option requires something completely new in the Code, or requires us to cooperate with parties outside our jurisdiction, it will carry a greater implementation risk than a familiar approach that is completely within our control …. All government interventions carry the risk of unintended consequences, including that the original aim of the intervention is not achieved. **We prefer options that can be implemented in a way that minimizes this risk**."* [our emphasis]

We agree wholeheartedly with these sentiments.[17] However, for the reasons set out above, the Authority's proposed reforms to the PDP are demonstrably at odds with these guiding principles. Most notably, there is a considerable risk of unintended consequences arising from what is an economically unprincipled, inequitable and inadequately specified proposal. Moreover, as we mentioned above, the Authority is not the appropriate body to be making determinations about when businesses should be offered financial assistance to prevent or

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[16] Electricity Authority, *Hedge Market Enhancements (market making) Ensuring market making arrangements are fit-for-purpose over time*, Discussion paper, November 2019, p.25.

[17] The objectives set out above are completely consistent with the fundamental tenets of best practice regulation that we articulated in our submission in response to the Third Issues Paper. Specifically, we stated that any regulatory intervention should be addressing a material and enduring problem in the least interventionist manner possible and based on robust economic foundations and cost benefit analysis. See: Northpower, *2019 Issues Paper Transmission Pricing Review,* 1 October 2019, p.2.

postpone their exits. That is a job for central Government, which can make well-informed judgements on a case-by-case basis.

4. Asset valuation methodology

Northpower does not support the Authority's proposal to apply a DHC methodology to all investments earmarked for BB charges. It would produce an inefficient time profile of prices that would discourage/encourage consumption at precisely the wrong times. It would also risk providing Transpower with inappropriate incentives to 'sweat' old assets. Applying an indexed historical cost (IHC) approach would assuage these problems.

4.1 Application to a regulatory asset base

Transpower's annual revenue allowance (its 'Individual Price-quality Path (IPP)') is determined in part by applying straight line depreciation to its entire regulatory asset base (RAB).[18] That return of capital component (depreciation) consequently assumes that the economic/replacement values of assets depreciate uniformly over their lives. However, that is almost never the case, in practice.

For example, the economic value of a transformer that is expected to last for, say, 20 years, is likely to be relatively constant over the first, say, 10 or 15 years of its life. However, as it approaches the end of its useful life and its replacement becomes imminent its economic value may start to deteriorate quite rapidly. It follows that applying straight line accounting depreciation to long-lived network assets (such as transformers) will tend to:

- **understate** asset values – and consequently **overstate** the required return of capital (depreciation) – in the early years of an asset's life;[19] and
- **overstate** asset values – and therefore **understate** the necessary return of capital – towards the end of an asset's life.[20]

This caused the Australian Competition Tribunal to observe that straight-line depreciation was "too crude a tool to be used where there is the opportunity for a more sophisticated analysis".[21] Why then is it used so widely by regulators – both in New Zealand and overseas? The answer is simple: convenience. Alternative depreciation approaches (e.g., variants of economic or 'NPV' depreciation) tend to have more demanding information requirements that make them far more difficult to implement. Moreover, the inaccuracies inevitably associated with straight line depreciation are 'masked' to a large degree when it is applied to a RAB comprising assets of many different ages.

This 'masking' effect occurs because, in any given year, for every 'older' asset being under-depreciated there may be a 'newer' asset being over-depreciated. Because the RAB is constantly being updated as the business builds more assets and replaces old infrastructure,

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18 The RAB increases in value as new investments are made and declines over time as depreciation is applied and Transpower disposes of assets.

19 For example, a one-year old transformer will likely *not* have depreciated in value by the amount implied by the application of straight-line depreciation. Rather, in economic terms, the asset may be worth nearly as much as it did when it was newly installed. Application of a DHC methodology with straight-line depreciation will therefore result in an annual return of capital allowance that is *too high* in that year.

20 For example, a nineteen-year old transformer that is on the brink of being replaced may well have depreciated by *more* in the previous year than the amount implied by the application of straight-line depreciation. Applying a DHC approach with straight-line depreciation will therefore result in an annual return of capital allowance that is *too low* at that particular point in time.

21 *Re East Australian Pipeline Ltd* [2004] ACompT 8 (8 July 2004), para, 38.

these ‘overs’ and ‘unders’ may cancel each other out to a substantial degree. The resulting *overall* return of capital (i.e., depreciation across *all* the assets comprising the RAB) may consequently be broadly accurate. Most regulators are therefore prepared to implement a simple straight-line depreciation approach to determine a total annual revenue requirement (or an overarching weighted average price cap).

However, once that total revenue requirement has been determined (the ‘size of the pie’), a completely different approach is then invariably employed to set prices for bespoke regulated services (the ‘size of the slices’). For example, a long-run marginal cost (LRMC) methodology might be employed to define prices for certain services. Indeed, a DHC approach – combined with straight-line depreciation – is *never* used to set prices for individual *assets/investments*. There are very good reasons for this, as we foreshadowed above and explain further below.

4.2 Application to individual assets/investments

The Authority is proposing to apply a DHC approach with straight-line depreciation to set prices for all investments earmarked for benefits-based (BB) charges. In other words, the prices for those bespoke investments would be informed by the annual allowance included implicitly in Transpower’s IPP. We do not agree that this is the appropriate approach. As we have seen already, although Transpower’s *total* annual depreciation allowance may be broadly appropriate within the context of its IPP (i.e., its *total* revenue allowance across *all* assets), the sums applied to *individual assets* are often economically nonsensical when viewed in isolation.

Straight-line depreciation only really makes sense as an analytical approach when it is applied to a large group of assets of different ages, so that the accuracies intrinsic in the methodology are diluted over that pool. If the approach was to be employed at a more disaggregated level to set prices for individual assets/investments, then all those inaccuracies and inefficiencies would be ‘unmasked’, creating all manner of problems. Unfortunately, that is exactly what the Authority is proposing to do. This would create a highly inefficient time-profile of prices.

Specifically, as we mentioned earlier, the crude mechanics of straight-line accounting depreciation would mean that the BB charges for an individual asset/investment would be at their highest immediately after it had been commissioned, when:

- there is typically plenty of spare grid capacity that, ideally, Transpower would like customers to utilise (especially given the ‘lumpy’ nature of most investments);
- the short- and long-run marginal costs of using the grid would be at the low points in their cycles (on account of the prevalent spare capacity); and
- there would be likely to be comparatively fewer beneficiaries – and aggregate benefits – than later on the investment’s life once demand has grown.

Conversely, BB charges for an individual asset/investment would be at their absolute nadir – possibly even at *zero* – right before a new replacement investment needed to be undertaken, at which time:

- capacity would typically be scarce, i.e., Transpower might ideally like customers to curtail their demand at those times in order to defer the need for that new investment;
- SRMC and LRMC would, in all likelihood, be peaking; and

- there would be likely to be more beneficiaries and greater aggregate private benefits due to historical demand growth.

If the Authority's objective is to set efficient transmission prices over time – which clearly it should be – then applying a DHC approach (with straight line depreciation) to set BB charges for individual assets/investments is consequently one of the *worst things that it could possibly do*. It would serve to discourage/encourage consumption at precisely the wrong times. The proposal is therefore inconsistent with the most basic principles of efficient network pricing. Compounding matters, it would also create a host of potential *practical* problems for Transpower to manage.

The perverse time-profile of prices described above would mean that customers would face sharp price increases whenever a 'BB investment' was replaced. One day customers could be paying next to nothing for an asset and, on the next, a very steep sum. It is easy to imagine that this might cause those customers to exert pressure on Transpower to delay replacing an asset – to 'sweat' it – in order to postpone the impact of the ensuing price increase. If Transpower obliged – which might often be the most expedient course if there is some discretion – then, in time, this could compromise reliability and security.

In summary, there is a crucial difference between applying straight-line depreciation to a RAB as opposed to individual assets/investments. Further, there does not need to be alignment between the IPP (revenue) and TPM (pricing) regimes. Applying a DHC approach at both stages with straight line accounting depreciation would be inconsistent with economic orthodoxy and compromise both allocative and dynamic efficiency.

4.3 The solution: apply the IHC approach to all assets

Applying an indexed historical cost (IHC) approach to all investments earmarked for benefits-based (BB) charges would assuage all the problems described earlier. As the Authority has acknowledged,[22] the methodology would result in a more conventional 'flatter' time profile of charges (in real terms). This would remove the counterintuitive – and highly inefficient – 'saw-tooth' pattern that would otherwise incentivise perverse consumption behaviour. It would also remove any risk of Transpower 'sweating' older assets in order to postpone replacements and attendant price spikes, since tariff levels would not shift as abruptly.

The time-profile of charges would also accord more readily with the 'service-based' nature of the product in question. For instance, Air New Zealand does not reduce its fares on, say, the Auckland/Wellington route annually on 1 January to reflect the fact that one of the aircraft servicing the link is a year older. In the same vein, the value of the transmission service provided by, say, a transformer does not deteriorate by an equivalent sum in every year of its life. The DHC approach proposed by the Authority consequently bears no resemblance whatsoever to the way services are priced in most workably competitive markets.

Finally, the Authority has continued to express some reservations about the implications of applying an IHC approach on the quantum of revenue that would need to be recovered via the residual charge. As several parties have noted,[23] these concerns are unfounded. For example, there is no reason to think that customers might end up 'over-paying' for existing interconnection assets that have been earmarked for BB charges if an IHC approach is

[22] Supplementary consultation paper, p.5.

[23] Axiom Economics, *Economic review of transmission pricing review consultation paper A report for Transpower*, September 2019, pp.67-68.

employed. Transpower has not applied bespoke interconnection charges for particular assets – including the six that have been flagged for BB charges. Instead, it has:

- calculated the annual revenue that it must recover through the TPM – the majority of which comprises a return on and of the depreciated value of its regulatory asset base, which comprises *all* of its assets, old and new; and
- set RCPD-based charges for *all* of its interconnection assets, i.e., there is a single bucket called 'interconnection revenue' – there are not 'multiple buckets' that allocate the costs associated with particular assets to certain customers.

It consequently makes no sense to ask whether applying an IHC valuation approach to specific assets would result in some customers 'overpaying' for those investments. There has *never been a price* for those individual assets under the TPM, so how could anyone possibly pay too much? There have instead been prices that reflect the value of *all* interconnection assets, which have been paid by *all* customers. There is therefore no basis for the concerns expressed by the likes of Meridian.[24]

Moreover, even if there was some reason to think that customers might 'over-pay' for those particular interconnection assets (which there is not), that would still not be a compelling reason to employ a DHC methodology. All that would mean is that more revenue would be recovered via the BB charge, and less through the residual – a simple 'waterbed' effect. Transpower could not possibly earn more revenue in aggregate, since that is capped via its IPP. Accordingly, there are numerous compelling rationales to *avoid* the DHC methodology and various persuasive reasons to *adopt* an IHC approach.

5. Lack of durability

The two remaining specific proposals – both of which would involve updating transmission charges with extended 'lags' – serve to highlight the intrinsic lack of durability within the regime that many submitters have emphasised repeatedly. As others have highlighted,[25] the Authority would confront an unavoidable trade-off when designing and implementing transmission charges under its proposed methodology:

- if charges were to be revisited or recalibrated regularly to better-reflect the current pattern of benefits (to the extent it can be ascertained), then this could cause customers to change their behaviour in inefficient ways to reduce or avoid those imposts; but
- if charges were to be locked-in and seldom – if ever – revisited, then this would not be durable either – it would instead be a recipe for ongoing controversy as parties understandably challenged those allocations and lobbied for them to be adjusted.

Throughout its entire TPM review – dating back to the 'SPD methodology' proposed in the 1st Issues Paper in 2012 – the Authority has been trying unsuccessfully to balance these competing considerations. The two proposed changes (to charge disconnecting customers

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24 Insofar as HVDC assets are concerned, Transpower's IPP contains a specific HVDC revenue allowance, which limits the amount that it is permitted to recover for those assets under the TPM. So even though BB charges would be applied to both Poles 2 and 3, Transpower would *not* be able to set charges that resulted in it somehow 'over-recovering' the costs of those investments. That would be impossible, because its IPP would prevent it.

25 *See for example:* Axiom Economics, *Economic review of transmission pricing review consultation paper A report for Transpower*, September 2019, p.8.

for 10-years following their exits and to update the residual charge allocations using a ‘7-year lagged 4-year rolling average’) represent its latest attempts to ‘thread the needle’. However, there is a good chance that all this will do is deliver the ‘worst of both worlds’; namely:

- it is possible that distortions to consumption and investment decisions would still occur despite those adjustments, compromising static and dynamic efficiency; and
- it is implausible to think that all customers would be content with the proposed ‘lagged’ arrangements, which are likely to be subject to endless lobbying.[26]

This serves to cast yet more doubt on the supposed ‘durability’ of the arrangements. Northpower remains unconvinced that the proposed approach would be more stable and less controversial than the status quo – or more modest, incremental alternatives (which, as we noted earlier, the Authority is yet to consider). Indeed, the very fact that the Authority is continuing to make such substantial changes to the proposed methodology at this advanced stage in the consultation process to address the perceived lack of durability speaks volumes. Moreover, as we stated at the outset, there are other more serious shortcomings that would also jeopardise the proposed methodology’s durability that have been neither addressed nor acknowledged.

6. Conclusion

Northpower remains very troubled by the course the TPM review appears to be taking. The four specific proposals set out in the Supplementary consultation paper do not appear to have robust theoretical or practical foundations – particularly those relating to the DHC valuation methodology and the PDP. The Authority is yet to address – or even recognise – the numerous other problems that stakeholders have identified with the proposed methodology. Further, the Authority’s proposed consultation timeframe does not appear to provide it with a sufficiently meaningful opportunity for it to undertake this vitally important step and to engage properly with market participants.

[26] For example, if there is a large change in consumption patterns that results in, say, a customer reducing significantly its use of the grid, then it is unlikely to be content to wait almost ten years to see that translate into a significant reduction in the residual charge.