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*Keeping the energy flowing*

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26 July 2016

Carl Hansen
Chief Executive
Electricity Authority
PO Box 10041
Wellington 6143

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

Dear Carl

# Transmission Pricing Methodology

Please find enclosed Transpower's submission on the Authority's Transmission Pricing Methodology (TPM) Second Issues paper consultation, date 17 June 2016.

We support the Authority's work to improve pricing arrangements where this promotes the long-term interests of consumers. In relation to the TPM we understand the Authority's concern that the prices are not as cost reflective, and price signals are not as well targeted, as they could be.

## Our submission

We have carefully considered the consultation paper and draft TPM Guideline. As the party responsible for implementing, then operating any new TPM, we want to ensure any changes are robust, fit for purpose are and practical to implement and operate.

In our submission we:

1. Recommend a simplified, staged approach to implementing the Authority's key proposals. This would reduce complexity, cost and risk and allow key benefits to be realised sooner.

   We think this approach would produce a durable TPM. It also has the best chance of being implemented within the Authority's desired timeframe.

2. Provide in depth comment on the Authority's draft TPM Guidelines. In the event the Authority does not accept our recommendation for a simplified, staged approach we comment on the draft Guidelines; including expressing serious reservations with aspects of the draft Guidelines.

We include analysis and evidence that has informed our submission and that we consider will be useful to the Authority and interested parties.

## Next steps

I appreciate you meeting last week with the Board Sub-Committee overseeing preparation of this submission. We found this helpful and were reassured by the Authority's willingness to give due consideration to alternatives such as the one we propose.

Transpower's Board would welcome an opportunity to meet with the Authority Board, when it has had an opportunity to consider submissions. This would provide an opportunity to discuss next steps, should the TPM Guideline change, including the processes and protocols.

In that regard, while we have distinct roles in this process, an ongoing dialogue would be helpful as Transpower develops the TPM. We will, however, need to ensure that this dialogue respects Transpower's role as developer of the TPM and the Authority's in assessing Transpower's proposal.

Finally, I reiterate the sentiment expressed by Mark Verbiest, Transpower's Chairman, that we are committed to continuing to help the Authority reach a robust decision. Similarly, we will do our best to implement any revised TPM Guideline as smoothly, effectively and quickly as possible.

Please get in touch if you have any questions or would like to discuss. My team will be in touch regarding next steps.

Yours sincerely

Andrew

Alison Andrew
Chief Executive Officer

# TRANSPOWER SUBMISSION:

## TRANSMISSION PRICING METHODOLOGY, 2ND ISSUES AND PROPOSALS PAPER

**26 JULY 2016**

Keeping the energy flowing

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# EXECUTIVE SUMMARY

1. It is clear from the 2nd Issues Paper that the Authority's principal objectives are to make transmission pricing more cost-reflective and to provide better price signals to grid-users to promote more efficient consumption and investment choices and, thereby, a more durable regime.
2. We agree there is scope to improve the current transmission pricing methodology (TPM) including to improve cost-reflectivity and the targeting of price signals and that this is likely to require some changes to the Guidelines.
3. We are committed to working with the Authority, and others, to achieve better outcomes for consumers and for the sector. As the entity responsible for implementing, and operating any new TPM, we also want to help ensure any changes are robust, fit-for-purpose and practical.

## Transpower's focus is on helping the Authority achieve its objectives

4. We agree that making prices more cost-reflective and improving the targeting of price signals can be better achieved through changes to the Guidelines but we have a number of concerns with the Authority's proposals. For example:
   - Removal of a peak price signal could trigger an 'over-correction' where demand spikes lead to significant transmission investment being brought forward; and
   - Area-of-benefit (AoB) charges would not provide the intended locational signal to generators and could result in inefficient investment decisions, as well as adversely impacting operation of the wholesale energy market.
5. Either of these unintended impacts alone could increase the cost of delivered energy to consumers and turn the cost benefit analysis negative. We are also concerned with aspects of the prudent discount policy, specifically the workability and efficacy of the 'plant exit' proposal.
6. Transpower is also of the view, due to the sequential nature of the process and need for new systems development, that the reforms could not be implemented in their current form in the timeframe[1] anticipated by the Authority. We discuss these issues in Parts 1 and 2.

## Transpower submits a simplified, staged approach to the Authority's TPM proposal

7. Transpower submits that a simplified, staged approach which is tightly targeted at the key problems identified by the Authority should be adopted. In Part 1 of this submission we outline what this simplified, staged approach would look like.
8. The simplified, staged approach incorporates the key elements of the Authority's plan[2], but is structured as a progressive transition from the current TPM to a revised TPM. It would achieve the Authority's key objectives but with less disruption, cost and risk. In addition, by simplifying and staging the introduction, key changes could be implemented sooner.
9. In Appendix A we provide a draft addendum to the current TPM Guidelines that would give effect to the simplified, staged proposal. In framing the addendum we have sought to minimise uncertainty and unnecessary change, noting the Authority's key objectives

[1] PWC's assessment of the proposal is that implementing the Authority's proposal for 1 April 2019 is "improbable" (refer Executive Summary in its attached report Appendix D). This is based on an assumption that the Authority would permit a maximum of one year for development of the new TPM.

[2] With some adjustments to address the most substantive concerns we have with the draft TPM Guidelines.

10. We consider this is a pragmatic, robust and durable approach. It would benefit from scrutiny from the Authority and other stakeholders. We believe only brief additional consultation, on our suggestions, as opposed to further extensive consultation, would be required.

## We also comment on the Authority's draft Guideline and suggest amendments

11. In the event the Authority rejects any or all of Transpower's points, we will do our best to ensure any revised or new Guidelines are implemented as smoothly, effectively and quickly as possible. We urge the Authority to take note of the important practical considerations identified in this submission since, in our view, the Authority has significantly underestimated the time and cost of implementing its proposals, as well as the difficulties in producing a robust benefit-method.

12. In Part 3 of this submission, in the interests of addressing the more pressing of these practical considerations, we provide a range of suggested amendments to the draft Guidelines. We consider these amendments would go some way towards addressing our concerns, but would not resolve the broader policy issues we identify.

13. In Appendix B we enclose an annotated track-changes version of the Authority's draft Guidelines that contains our suggested amendments.

## S15 objective provides the key anchor point for the reforms

14. The starting point of the TPM review lies in the Authority's statutory objective, under section 15 of the Electricity Industry Act 2010, namely: *To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long term benefit of consumers.*

15. Consequently, the changes being proposed by any party need to achieve and/or improve the individual elements of that overall objective:

    a. Competition;

    b. Reliable supply;

    c. Efficient operation; and

    d. For the long term benefit of consumers.

16. Any change that reduces the likelihood of improving one or more of these elements should be regarded with caution.

## We acknowledge the efforts to engage with the sector and Transpower

17. We acknowledge and appreciate the way in which the Authority has engaged during the consultation period as parties have sought to understand and test the proposals.

18. The Authority has demonstrated a commitment to the consultative process. We encourage the Authority to continue this commitment, and recommend calling for cross-submissions.

19. This submission comprises three parts:

    **Part 1** – A simplified, staged approach

    **Part 2** – General comments on 2nd Issues Paper

    **Part 3** – High level comments on the draft Guidelines (to be read in conjunction with Appendix B and expert reports).

    The submission also includes appendices containing analysis and evidence that has informed our submission and which we consider will assist the Authority and stakeholders.

# 1. PART 1: A SIMPLIFIED, STAGED APPROACH

In this part we outline why we consider the timetable proposed by the Authority is not realistic for the Authority's proposals in their current form.

We also outline why adopting a simplified, staged approach to reforming the TPM would substantially address the problems identified by the Authority, more quickly and with less cost and risk than would otherwise be the case.

## 1.1 IMPLEMENTATION FOR 1 APRIL 2019 IS NOT REALISTIC

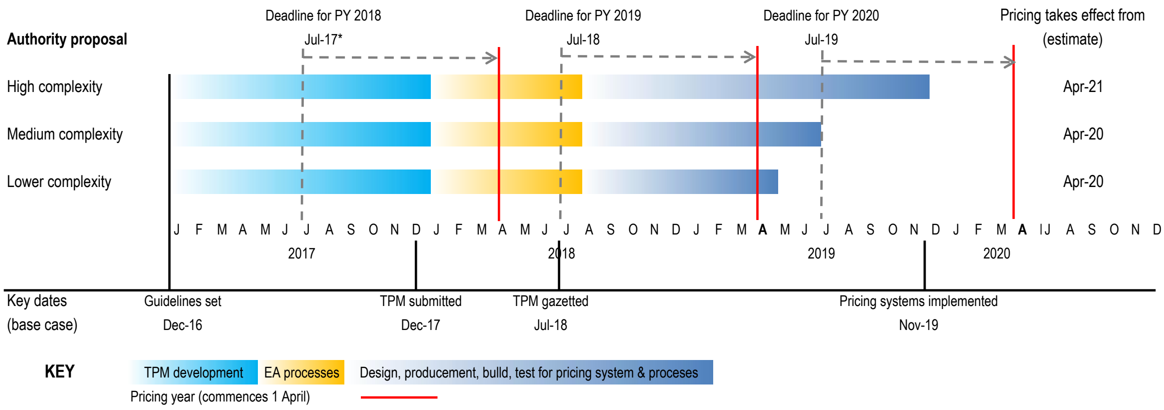
We support the Authority's objective of improving the efficiency of sector-wide pricing arrangements. We agree interconnection charges could be made more cost-reflective and price signals could be better targeted.

The Authority has been clear that it wants TPM reforms to be implemented as soon as possible. It has identified the pricing year commencing on 1 April 2019 as a target for the changes to take effect.

We have considered the Authority's proposals, and the challenges associated with implementing these. Our assessment is that the proposals in their current form could not be implemented by 1 April 2019. This view is informed by advice from PWC[3] but reflects our own assessment[4] of what would be involved in developing the new TPM, the Authority's regulatory processes, and, developing new pricing systems and processes.

Figure 1 contains Transpower's representation of three different complexity scenarios analysed by PWC[5] (who estimate the elapsed time to implement the Authority's proposal as 26 to 34 months). The 'high complexity'scenario most closely our understanding of the Authority's proposal.

**Figure 1: Scenario assessment of elapsed time to implement TPM changes**




* Deadline for completion of **major changes** to the TPM systems. Prices are notified to customers in November to take effect for the next pricing year (PY starts 1 April each year). This allows distributors to reflect transmission pricing in their own tariffs and in turn to notify retailers. This lead time also permits necessary customer consultation on the most complex aspects (connection charges), external audit and approval by Transpower's Board.

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[3] Refer to Appendix D page 8
[4] Which is informed by our experience with the 2014/15 TPM operational review.
[5] Refer to Appendix D page 20 for further details.

The analysis in Figure 1 is informed by key processes during the annual pricing round. For example, minor changes (and those not affecting connection charges[6]) could be made as late as September while major system changes (or those affecting connection charges) will need to be completed by July to flow into prices the following April.

Figure 1 also reflects PWC's analysis of the key steps involved in implementing the Authority's proposals once Guidelines are issued. These are:

- **TPM development:** the economic, technical and legal process of developing the new TPM. PWC assumes that Transpower will have 12 months to develop the TPM.

  In theory the Authority could provide as little as 90 days (the minimum allowed by the Code) but in reality, as the Authority's own process has demonstrated, even 12 months may be insufficient to develop what is essentially a new TPM.

- **Authority processes:** [specified in the Code]. Transpower recommended that PWC allow 6 to 7 months for this stage (we viewed the elapsed time for the TPM operational review as the minimum realistic timeframe for the Authority's processes).

- **System implementation:** designing, procurement, build and testing for pricing systems and processes. Project complexity has a significant bearing on the elapsed time (and cost) for this stage of the project. PWC estimates that system implementation for the 'high complexity' scenario would take 16 months.

We discuss implementation, including costs, further in Part 2 and include PWC's report at Appendix D. PWC is available to meet with the Authority and has offered to have its work reviewed by an independent expert, should the Authority wish to do so.

## 1.2 Key objectives could be achieved sooner, with less cost

We think a simplified, staged approach could better address the problems identified by the Authority – sooner, with less cost, risk and disruption – while implementing key features of the Authority's proposals (adoption of AoB, a residual charge, and LRMC pricing). We consider this approach is more likely to satisfy the Authority's statutory objective.

We believe that the simplified, staged approach that we propose would:

1. Allow the entire cost of the interconnected grid to be allocated via simplified AoB charges:
    i. Enhancing cost reflectivity by capturing approximately $360m of HVAC interconnection costs[7];
    ii. Simplifying the process of assigning remaining interconnection costs to areas of benefit; and
    iii. Producing a simpler, fairer and more durable AoB (and TPM) by treating all HVAC assets equivalently regardless of location and age.
2. Avoid potentially intractable debates and lobbying regarding the assessment of private benefits for sunk investments, and directly addresses concerns that locational signals for generators are poorly targeted; and

[6] Calculation of connection charges is the most involved component of the current TPM. It involves a bottom up reconciliation of connection assets to customers and verification of these by customers.
[7] In comparison to the approximately $180m of interconnection costs that the Authority estimates could be recovered through the AoB.

3. Truncate the implementation critical path by reducing system development needs and shifting from a linear or sequential process to one with overlapping stages. The effect of this could be to:
    i. Reduce implementation cost and delay risk due to system development issues;
    ii. Allow introduction of key elements up to two years sooner, and completion of the final stage sooner (or at the same time), than would otherwise be possible.

We outline the key components and stages of this simplified, staged approach.

### 1.2.1 Overview of simplified, staged approach

The key features of our proposed simplified, staged approach to TPM reform are:

- **Cost allocation**: Replacement of the current postage stamp cost allocation for existing interconnection assets with a **simplified AoB** allocation (for example, with asset location and value used as the primary proxy for benefit) to load.

  From the outset we estimate this could recover most, if not all, of the capital cost of interconnection assets (approximately $360m per annum). It could, in future, potentially be used to assign grid operating costs.[8]

  Treatment of new interconnection assets would be subject to the outcome of a review of non-simplified AoB options (see below) but in principle the simplified AoB could be used to assign a large proportion of future expenditure. For example, if established Capex IM thresholds were used, it could recover the cost of most or all capital expenditure below $20m.

- **Peak-usage price signalling**: Replace the RCPD peak price with **LRMC charges** or LRMC-like charges to signal or broadly signal the impact of peak-usage on transmission investment or where transmission investment is most likely to be needed.

  While the RCPD charge is not well correlated to LRMC, it provides a clear peak signal that has helped defer or avoid significant transmission investment (and probably investment in distribution networks and in peaking generation as well).

  Removing this signal risks triggering a surge in peak demand, potentially resulting in inefficient investment. We see it as essential that a credible peak price signal is developed before RCPD is removed. We consider this should be an LRMC or LRMC-like charge, designed to operate in conjunction with other peak management techniques (demand response, future ACOT arrangements etc.).

  **A residual charge (lump-sum or fixed charge)**: It is likely that even with the expanded simplified AoB that we propose and with an LRMC charge, a residual charge will be required to recover any unallocated common costs or other residual costs.

- **Non-simplified or 'standard' AoB:** Transpower to review adoption of a non-simplified AoB cost allocation (which estimates benefits in a more sophisticated way) for future investments over a certain threshold.

  This reflects a view that simplified and non-simplified versions of the AoB charge are required. This view appears reasonable; however it is also possible that the simplified AoB charge will prove adequate.

- **Generation locational prices**: Transpower to review replacement of the current HVDC (simplified North-South Island locational) charge with extended **locational prices for generation**.

[8] For example, a large proportion of the 'HVAC overheads' category in the current TPM (refer to Appendix F).

To limit wealth transfers between generators and consumers the TPM could link revenue recovered via the locational price to HVDC revenues (though the efficient level of revenue to be recovered through this charge could be higher or lower).[9]

The simplified, staged approach could include consideration or development of several of the Authority's subsidiary proposals. For example, some of the proposed changes to the prudent discount policy[10], development of a kVAR charge and changes to the loss and constraint excess.

It could also provide for the transitioning in of changes (for example where the changes result in large shifts in prices) and for the Authority to direct Transpower in some areas (changes to the HVDC charge, for example).

We consider our proposal to be a pragmatic, robust and durable approach. It would benefit from review by the Authority and other stakeholders, and we invite this scrutiny.

### 1.2.2 Why we are proposing a simplified, staged approach?

Our view is that a simplified, staged approach applies the AoB concept in a pragmatic and workable manner and unlocks the potential benefits of reform sooner. This approach also reduces the cost and risks of a 'big-bang' change where a problem in one area may delay the whole project.

Although the simplified, staged approach incorporates key aspects of the Authority's proposal it:

- Applies the AoB charge more broadly than proposed by the Authority (including allowing the bulk of the costs of the interconnected grid to be allocated via the AoB charge from the outset).
- Provides conventional explicit ex ante dynamic pricing signals rather than implicit and uncertain 'shadow prices' (though this could also be introduced under the Authority's proposal).
- Avoids the need for subjective, contentious and costly ex post assessment and determination of private benefit for sunk investments.
- Avoids the risk that AoB charges do not provide the intended locational signal to generators and, in contrast, create inefficient investment signals, and adversely impact operation of the wholesale energy market. (We recognise that a similar, though smaller risk exists in relation to location pricing for generators.)
- Would be simpler and therefore better understood and would treat assets and customers equivalently (non-discrimination) and therefore likely to be perceived as be fairer and more durable.

It also allows key aspects of the reforms to be introduced sooner than under the Authority's proposals and is likely to have lower implementation and ongoing operational costs than the medium and high complexity scenarios (which reflect the Authority's proposal) assessed by PWC.

We have not subjected this proposal to a proper cost benefit analysis but, instead, have relied on the Authority's problem definition. We would conduct CBA for the design components in the implementation of the proposal, and for the additional components, if it were to be taken forward. We consider that it is likely that this proposal would result in lower implementation costs and could result in higher and more certain net benefits than the Authority's TPM proposal in its current form.

The components of this proposal, and how they are specifically directed to the problems the Authority has identified, are discussed below.

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[9] HVDC revenues are forecast to decline from $150m in 2016/17 to less than $100m in the early 2020s.

[10] Noting that, while we understand the Authority's objective, we have reservations about the workability and efficacy of the 'plant closedown' part of this proposal.

*Why didn't we propose this approach earlier in the Authority's review process?*

The simplified, staged proposal that we outline above is consistent with views we have expressed in submissions and to stakeholders during the intervening period. For example, we have consistently emphasised a few basic points:

- The need for a clear problem definition and the importance of assessing reform options against that problem definition;
- Overly intricate solutions based on sophisticated models like vSPD are seductive but provide a false precision that usually does not withstand scrutiny (or at least are highly contentious); and
- The importance of adhering to some basic principles such as time-neutrality, as a means of promoting durability.

Although we have emphasised these points before, the 2nd Issues Paper provides the first opportunity to consider a formal proposal from the Authority since its first Issues Paper in 2012.

### 1.2.3 Staged introduction, potentially starting as soon as 1 April 2018

By simplifying and staging the development and implementation of changes to the TPM, we think each component of the modified proposal could be introduced sooner (or at the same time for stage 3) than would be possible under the draft Guidelines.

Table 1 describes the potential staged transition from the current TPM to a new TPM.

**Table 1: Implementation stages for simplified, staged approach**

| Stage* (timing) | Existing component | Suggested Replacement and comment |
|---|---|---|
| **Stage I (target 2018)** | Use of postage stamp cost allocation for interconnection costs | Partial replacement of the current postage stamp cost allocation for existing interconnection assets with a **simplified AoB** allocation (for example, with asset location and value used as the primary proxy for benefit) to load. This could assign approximately $360m of interconnection costs via the AoB.<br>New interconnection assets would also be allocated via this simplified AoB, subject to the outcome of a review of non-simplified AoB options (see below).<br>This could potentially be undertaken relatively quickly, as it is likely to have limited system impacts – the principal issues to be dealt with would be the number of regions, asset valuation methodology, and allocation of assets shared amongst the regions. A transition period may be warranted to avoid price shocks. |
| **Stage II (target 2019)** | Recovery of interconnection through RCPD charges | Introduction of **LMRC** (long run marginal cost)**, or LRMC-like, charges** and a **Residual Charge** to recover the AoB allocation.<br>The key issues would be:<br>• Identifying regions or areas where targeted LRMC charges would efficiently defer investment, developing a methodology for setting LRMC charges and determining when they should apply/be removed; and<br>• Establishing the least distortionary residual charge option.<br>The Authority's work on LRMC and assessing different residual allocators would inform the development of both charges. |
| **Stage III** | New investments | **Additional component A:** Transpower to review whether a non-simplified, **AoB** cost allocation should be applied which estimates benefits in a more |

| Stage* (timing) | Existing component | Suggested Replacement and comment |
|---|---|---|
| **(Target 2019 - 2020)** | (over Capex IM thresholds) | sophisticated way.<br>This non-simplified AoB could be applied to capital expenditure in excess of key Capex IM thresholds for major capex and base capex. Base capex >$20m carries special consultation obligations while major capex projects require approval by the Commerce Commission (in addition to special consultation obligations).[11]<br>Any other new capital expenditure would be subject to the simplified AoB. |
| | Interconnection and HVDC link | **Additional component B:** Transpower to develop **locational pricing for generation** (this could replace the current HVDC charge).<br>The key issues would include the extent to which locational signals can influence generation location choices, how this impacts on transmission investment requirements and on the wholesale electricity market (and generator offers). |
| **Other** | Transition, HVDC, PDP, kVAR | **Transition:** the current Guidelines and the 2012 draft Guidelines included provision for transition to mitigate price shocks. We suggest this provision should be retained (recognising it may not be required).<br>**HVDC:** The staged approach outlined above could be adapted to accommodate any Electricity Authority direction to change the HVDC[12] charge (the question of whether South Island generators should continue to pay any or all of the costs of the HVDC link appears to primarily be an equity / durability one that the Authority is best placed to address).<br>**PDP:** Some of the modifications to the Prudent Discount Policy could be introduced at any of the three stages.<br>**kVAR:** Other minor changes such as the kVAR charge are not included at this point but could easily be added to the simplified, staged approach. |

Notes: * The staging outlined above reflects the expected difficulty of each change including the need for system changes and prioritises introduction of LRMC pricing (estimated by Oakley Greenwood to provide $213m NPV efficiency gains).

The combination of simplifying and staging implementation reduces bottlenecks at each stage of the implementation process. Figure 2 compares this approach with the three complexity scenarios assessed by PWC.[13]

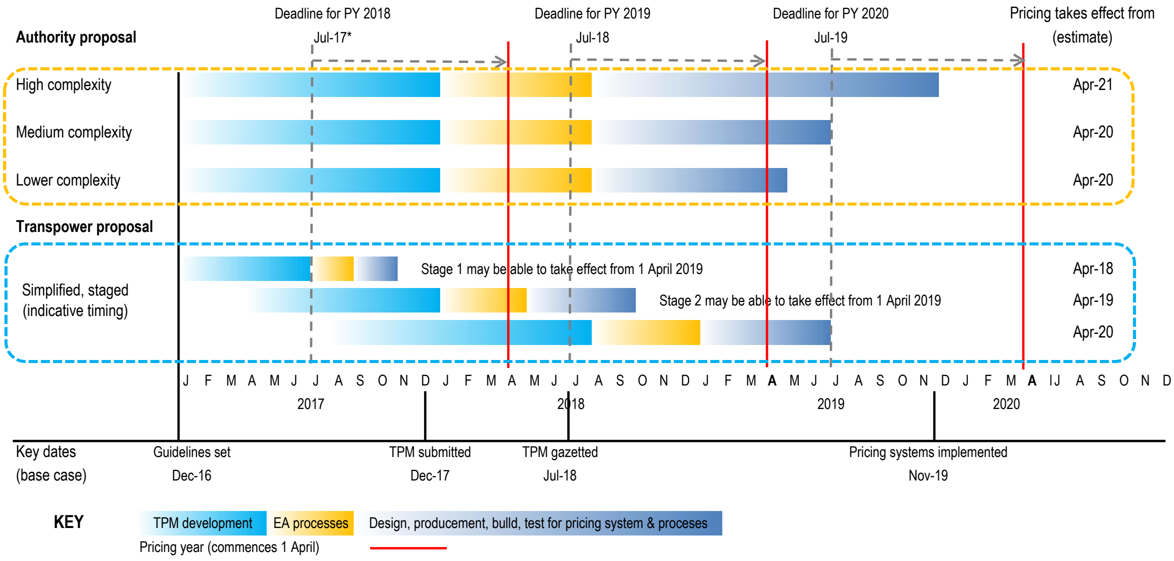
We have not undertaken a detailed assessment of the costs to implement the simplified, staged approach that we propose; however, *for purposes of cost estimation* we consider this is most analogous to the 'medium complexity' scenario.

[11] Major Capex is enhancement and development expenditure above $20m. Base Capex is replacement and refurbishment expenditure plus enhancement and development expenditure below <$20m.

[12] The Authority's modelling indicates that it believes North Island consumers should be made to pay around 55% or $70m pa. of HVDC costs.

[13] As noted previously, the PWC timeframes for the Authority's TPM proposal assume that TPM development would be 12 months. We consider our simplified, staged approach could be implemented sooner than the Authority proposals under all scenarios.

Figure 2: Comparison of implementation approaches




* Deadline for completion of **major changes** to the TPM systems. Prices are notified to customers in November to take effect for the next pricing year (PY starts 1 April each year). This allows distributors to reflect transmission pricing in their own tariffs and in turn to notify retailers. This lead time also permits necessary customer consultation on the most complex aspects (connection charges), external audit and approval by Transpower's Board.

## 1.2.4 PRICE IMPLICATIONS

We have started, but not completed, high level analysis of potential price outcomes under the approach outlined above.

However, to give an indication of high level price impacts under a simplified, staged approach we provide the following indicative estimates of price estimates. They are based on assigning the capital cost of the entire grid to the existing four regions using the approach we propose and assigning the residual using the allocator adopted by the Authority for the residual.

Table 2: Indicative price regional price impacts

| Region | Status Quo interconnection (IC) $ | Status Quo IC % | AoB for all IC assets | Residual (using GAMD) | Regional allocation (AoB + Residual) $ | Regional allocation (AoB + Residual) % | Change from Status Quo |
|---|---|---|---|---|---|---|---|
| UNI | $218m | 33% | $142m | $99m | $241m ($266m)* | 36% | +10% (+22%)* |
| LNI | $217m | 33% | $113m | $104m | $217m ($257m)* | 32% | -1% (+17%)* |
| USI | $112m | 17% | $55m | $53m | $108m | 17% | -4% |
| LSI | $114m | 17% | $52m | $45m | $97m | 15% | -15% |

Notes: For the scenario modelled in this table we assign $360m via the AoB charge using asset location and value (Replacement Cost[14] – indexed to 2012) and $302m[15] via the Residual charge using gross anytime maximum demand (GAMD) as the allocator. *Bracketed numbers include the Authority's modelled allocation of HVDC costs to NI consumers.

[14] We use the same methodology as applied in the current connection charges framework. In Appendix I we briefly consider the merits of using RC versus depreciated historic cost (DHC) for pricing purposes.

The impact on individual customers within each region would vary depending on the design of the individual tariff and each customer's load profile. For example, we have used GAMD as the residual allocator for this illustration (this is the allocator used by the Authority). This allocator would tend to assign more cost to customers with high levels of load control or distributed generation i.e. those who have responded to the price signals in the current TPM.

### Other observations

Some other observations about potential price impacts of the simplified, staged approach:

1. A peak price signal is likely to be retained in many, though possibly not all, parts of the country. This may not affect the allocation of costs between regions but would affect prices to individual customers within each region.
2. Changes are likely to occur sooner than would otherwise be the case, but are likely to be less severe (wealth transfers are smaller[16]) and involve a 'natural transition' because the implementation is staged over several years.
3. The allocation of costs between generators and load *may* be similar[17] to the current TPM though the allocation between individual generators is likely to change if locational pricing for generators is introduced.

A number of the features we describe above would also apply, in full or in part, if the Authority accepts the changes we suggest to its draft Guidelines.

## 1.3 Focus on core concerns with the current TPM

Our proposed approach is focused on achieving the Authority's principal objective of making prices more cost-reflective and improving the targeting of price signals (and doing so in as timely way and as effectively as possible).

Our proposed approach is focused on addressing the following principal aspects of the Authority's problem definition:

- Charges for recent investments are not service-based or cost-reflective;
- Poor price signals are incentivising inefficient investment and inefficient use of the interconnected grid; and
- Inefficiencies caused by generators not paying interconnection charges.

### 1.3.1 Authority concern that charges are not service-based or cost-reflective

The Authority has detailed that post-2004 transmission investment has been undertaken largely to meet demand in the UNI region (48% of transmission investment (including HVDC)) but that the costs have been shared across all four regions.

[15] Including the current TPM cost category referenced by the Authority "HVAC overhead" which contains $198m in unallocated operating costs and overheads. Appendix F breaks the category down and describes its main components.
[16] Primarily because the AoB charge is more inclusive and time neutral (it uses indexed RC).
[17] Either by coincidence or if the Authority sought to limit wealth transfers between generators and consumers, for example, by linking revenue recovered through the generator locational price to HVDC revenues.

The $1,342m of transmission investment in UNI translates to a revenue requirement of $201m, but the actual increase in interconnection charges from 2008/9 to 2015/16 has been $97m, with the difference spread over the other three pricing regions.[18]

The Authority noted "The projections for regional development and population growth in Auckland versus the rest of the country suggest the imbalance ... is likely to increase in the future".[19] We have considered this imbalance in relation to all transmission interconnection assets (pre and post-2004) and contrasted different asset valuation approaches. This is shown in Table 1.

**Table 3: Transmission interconnection assets by region and impact on revenue requirements**

| Region | Status Quo $m (RCPD) | % total | Replacement Cost $m (indexed to 2012)*,** | % total | Implied 'shortfall / over-payment' $m |
|---|---|---|---|---|---|
| UNI | 218 | 33% | 260 | 39% | -$42 |
| LNI | 217 | 33% | 207 | 31% | +10 |
| USI | 112 | 17% | 101 | 15% | +11 |
| LSI | 114 | 17% | 95 | 14% | +19 |

Notes: * Where assets straddle more regions we have applied a 50/50 split between the relevant regions, with the exception of the 220kV circuits from Whakamaru northwards 100% of which have all been assigned to the UNI. Note: If the 50/50 split were also applied to those lines the respective UNI and LNI allocations would be 33% and 37% for RC.

** Transpower holds historical 1998 RC asset valuations for asset types which we have building blocks for. For the purposes of this exercise the historical RC values of these assets were escalated by a factor of 1.42 to reflect CPI increases from 1998-2012. Asset types we do not hold asset building blocks for (such as land, easements, 400KV lines etc.) have been valued at actual cost.

Table 3 shows that the LSI region, and to a lesser extent the USI and LNI regions, contribute more to the cost of the grid than implied by the cost of the assets located in each region. Conversely, the UNI contributes less to the cost of the grid than implied by the costs of the assets located in that region.

The difference between Table 3 and the analysis in the Authority's problem definition is that we have taken into account the contribution of UNI to pre-2004 assets used to supply other regions and have valued assets on a time-neutral basis (using indexed RC rather than on a DHC basis).

An important caveat on this analysis is that for simplicity we have assigned 100% of interconnection revenues on the basis of regional asset values (using indexed RC). However, as only a proportion of interconnection revenues are likely to be allocated via the AoB charge,[20] the true split will also be affected by the residual allocator.[21]

## A straightforward solution

We suggest that the most straightforward way to address the Authority's concern would be directly through regional cost allocations. The current postage stamp could be amended to become a simplified AoB charge with, for example, asset location and value used as the primary proxy for benefit.

[18] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2015, Table 3.

[19] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2015, paragraph 6.53.

[20] The Authority modelling suggests approximately 26% of HVAC (and 100% of HVDC) revenues. Transpower's analysis, reflected in Table 2, indicates as much as 55% could initially be assigned via the AoB charge, potentially more if some common costs can be directly assigned.

[21] Appendix G shows how Transpower's customers are affected by different allocators (for those we were able to analyse during the consultation period).

The Problem Definition does not suggest the Authority's concern is more granular than the existing four regions. However, an assessment could be made to determine whether the simplified AoB charge should be extended to more than four regions – the Authority considered seven regions, for example, when it considered a zonal beneficiaries-pay option. Other possibilities are using Transpower planning regions.

It would be a relatively simple matter to adjust the cost allocations amongst the regions on the basis of the regions the assets serve. Some boundary issues are likely,[22] but we consider these would be relatively minor for the current RCPD regions (though would become more complex if a more granular approach was adopted).

Although this approach would recover the bulk of the current interconnection charge,[23] a residual charge would still be required to recover unallocated and common costs. We suggest that RCPD is retained as an allocator for the residual for the first year and is replaced by an incentive free allocator when an LRMC charge is introduced.

## Consideration of a non-simplified AoB

We suggest that, as an additional component, the Authority direct Transpower to consider whether a non-simplified AoB cost allocation should be applied (particularly for future grid upgrades). In essence, we do not believe the time it would take to develop a non-simplified AoB should delay simpler, changes that could be introduced earlier (the Stage I reforms).

The 2014/15 TPM Operational Review helped highlighted the benefits that can be brought forward by initial adoption of simple options. There is also a key pragmatic reason for distinguishing between sunk and new grid upgrades. The older the eligible investment the more speculative the counterfactual used to calculate the AoB charges becomes (i.e. what alternative transmission and generation would have occurred absent the eligible investment?).

The respective benefits of any (sunk) eligible investment to generators and load depend on the assumptions that are made about the cost of these alternatives. The sensitivity of the results to the assumptions adopted could swing the AoB calculation anywhere from assessing load (or generation) as the majority beneficiary to the minority beneficiary.

In relation to new grid upgrades (approved by the Commerce Commission) the counterfactual would be more obvious (i.e. no new upgrade or the next best alternative). Also, for prospective investments over certain thresholds[24] most, if not all, the assumptions and information required to establish the counterfactual would have been produced through the grid investment analysis.

### *Design of a non-simplified ('standard') AoB charge*

We have given considerable thought to the design of a non-simplified (or 'standard') AoB charge. Although we have not reached any firm conclusions, we have identified some particular issues that would need to be resolved and which may shape the development of this charge. Two inter-related examples which highlight the trade-offs that would need to be made are:

**1. The type of benefits and how these are assessed**

The consultation paper refers to private benefits (i.e. which include both efficiency benefits and wealth transfer benefits) and the Authority's modelling through the TPM review process has

[22] For example, how the costs of assets that span more than one region are allocated.
[23] We estimate this charge could recover approximately $360m (or 55%) of current interconnection charge
[24] Investments over $20m carry additional consultation requirements and, for Major Capex (enhancement and development over $20m) require Commerce Commission approval.

attempted to generate prices based on a vSPD analysis of private benefits. However, the draft Guidelines are silent on the type of benefit that should be used.

The choice of benefit type is significant because:

- **Private benefits are difficult to estimate robustly or precisely** and model-based estimates are driven by both design choices and input assumptions and are extremely volatile. These issues have been well traversed before, and we include Scientia Consulting's report on this matter at Appendix E.[25]
- **Transpower invests on the basis of market benefits (efficiency benefits only)** and, while market benefits estimation is less volatile, there is no obvious correlation between these benefits and private benefits. For example, there is no necessary correlation between the efficiency impacts of an investment and the price impacts (wealth transfers).[26] The disconnect between the basis on which we invest and private benefits will be an issue if the latter is used to set prices.
- **We recognise the difficulty of estimating (market) benefits robustly**. It is for that reason that we make extensive use of scenarios and sensitivity analysis in our investment planning to test the effect of future uncertainty and ensure the option we select is robust. This analysis attempts to identify the potential range of future benefits, rather than the absolute value of the benefits.
- The assessment of benefits for the AoB charge would require choosing a particular value for the benefits. This could be done by using an average over a range of scenarios, as we do for investment decision making, but it would nevertheless rely on assumptions and therefore be inherently uncertain.

This has implications for the robustness, and therefore durability, of prices set under this approach.

**2. The degree of granularity**

It is not especially difficult to generate an estimate of benefits (market or private). This can be done using the planning tools we use for investment analysis – or via models such as the vSPD methodology, which can generate estimates at a very granular (e.g. nodal) level. But producing estimates is not the challenge – it is the **robustness** of those numbers that is the larger issue.

The models that can be used to produce estimates of benefits are invariably highly sensitive to small changes to design parameters and input assumptions. Small changes in either can lead to dramatic changes in the estimates of benefits. It could be the difference between a designated transmission customer being identified as a primary or a minor beneficiary of an investment.

This is an issue when using these tools for investment decision making but it would be an even larger problem when using such tools to set prices for individual grid connections and customers. For example, an ex-ante modelling approach to identifying benefits requires a large range of assumptions to be made about the future.[27]

While we are continuing to explore these issues, we have genuine and serious reservations about attempting to use planning models to assign costs at a very granular level.

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[25] Scientia Consulting: Technical review of vSPD Area of Benefit method (Appendix E)

[26] For example, our preliminary estimates show *system benefits* to date of approximately $3m from last year's changes to HVDC pricing and *private benefits* of approximately $65m. A summary of this analysis is included in Appendix H.

[27] For example, electricity demand growth, the future of existing generation, new generation build, generator availability, generator short-run marginal costs, network configuration, unserved energy values, and, if private benefits are to be allocated, generator bids.

One way to mitigate this problem (and make the benefit allocation more stable) would be to allocate over zones or regions only, rather than individual nodes. This would recognise the limitations surrounding the level of accuracy of assumptions and minimise potential inequities. The zones or regions would need to be identified but, in our view, such an approach would help balance the tension between identifying beneficiaries and durability of the pricing methodology.

### 1.3.2 Authority concern about poor price signals

The Authority expressed concern that "The TPM inefficiently discourages use of the interconnected grid after an investment to increase the capacity of the interconnection grid"[28] and "usage charges rise just as the marginal cost of using the relevant circuits steps down sharply".[29]

We broadly agree with this assessment (as the Authority points out, we identified this issue through the TPM Operational Review). The Authority also expressed concern that RCPD charges:

> "inefficiently discourages grid use at peak periods"

on the basis that

> "The interconnection charge … is based on the customer's use of the interconnected grid (excluding the HVDC link) that coincides with the occurrence of the 100 highest regional peak demand periods in a year. This distorts the signal provided by nodal prices during these periods. It encourages grid users to suppress their demand for grid-supplied electricity when there is no economic benefit from doing so".[30]

The key difficulty with the RCPD charge under the current Guidelines is that it has to allocate around 70% of the total costs of the grid through a peak price, with only limited levers to adjust or dilute the price signal.

While we consider the AoB charge has conceptual merit as a means of allocating costs (as does Ramsey Pricing), the conditions required for it to form a 'shadow price' signal do not hold in relation to interconnection or HVDC assets (we outline our views on the 'shadow price' in Part 3). We therefore do not agree that it provides a useful forward-looking price signal.

However, an LRMC charge could provide an efficient forward-looking signal. In conjunction with the AoB allocation and residual charge, an LRMC charge could enable cost reflective pricing using a two-part tariff structure where:

- The LRMC charge provides a usage or peak usage charge to signal the cost of capacity constraints; and
- The AoB allocation and residual charge recovers the remainder of costs in as non-distortionary manner as possible.

For these reasons we propose adoption of an LRMC charge alongside the AoB and residual charges.

### 1.3.3 Authority concern that generators do not pay interconnection charges

Any change to the TPM to charge generators for interconnection services would be a major change to the TPM.

Our starting point is that charging generators for connection means their charges broadly cover the incremental cost of providing transmission services. Generators also contribute to common costs (which include unallocated grid costs related to interconnection assets) through the overhead

[28] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2015, paragraph 6.26.
[29] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2015, paragraph 6.28.
[30] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2015, paragraph 6.36.

injection charge.[31] In aggregate, generators currently pay $39.1m in connection charges, including injection overhead, and 100% of the costs of the HVDC are borne by South Island generators.

In our view, there are two broad reasons for charging generators for interconnection services:

- As a way of broadening the tax base (reducing any inefficiencies from recovery of the cost of transmission services) to improve static efficiency. (The tax base argument is essentially the position advocated by Dr Marcelo Schoeters and Pablo Spiller, of Compass Lexicon, on behalf of Vector.)
- To enable introduction of a (dynamically efficient) locational price signal. At present the only non-energy market locational price signal to generators is provided via the HVDC charge.

Any assessment of whether to extend transmission charges to generators should be weighed up against the types of considerations the Authority used in the 2nd Issues Paper to apply the residual to load only. We agree with the Authority's view that:

> generation is more likely than load to alter its behaviour if the residual were applied to both. Thus applying the residual charge to generation is likely to result in more costly distortions to generator investment and operation decisions. For example, some submitters have argued that applying the charges to generation would create incentives for generators to inefficiently amend their wholesale offers in order to avoid charges.[32]

The same arguments are applicable to the proposed AoB charges. However, we recognise one of the other difficulties with the Authority's proposal is that the overall quantum of charges to consumers increases significantly (while the quantum of charges to generators would decrease correspondingly).

One pragmatic solution could be to link revenue recovered via the locational price to HVDC revenues (though the efficient level or revenue to be recovered through this charge could be higher or lower).

[31] Generators currently pay approximately $14m per annum via the injection overhead charge.
[32] Electricity Authority, Second Issues Paper, Transmission Pricing Methodology: Issues and proposal, 17 May 2016, paragraph 7.198.

# 2 PART 2: GENERAL COMMENTS

In this section we make some overarching observations that we consider are relevant to any TPM reform proposal. We also outline:

- The approach we have taken in this submission and comment briefly on process;
- An overview of key concerns with the proposals and comment on the cost benefit analysis; and
- Our initial view on the process we would follow if the Authority amends the Guidelines.

## 2.3 Consideration

We have carefully considered the Authority's proposals. We have done so from the perspective of the party charged with implementing these and operating the future TPM (including considering how new pricing would flow through to and impact future expenditure decisions).

Transpower completed the first 'operational review' of the TPM, last year. This resulted in the Authority making several changes to the TPM that (partially) addressed problems identified by stakeholders with the HVDC and interconnection changes. It also allowed Transpower and the Authority to test processes that would apply if the Guidelines were amended or replaced.

Earlier this year we published a forward looking document entitled 'Transmission Tomorrow'. This document, and the analysis that informed it, has had implications for the way we manage our business and think about investing in the grid.

With the benefit of this experience and analysis we have completed during the consultation period, we make the following overarching observations.

### 2.3.1 Clarity and alignment of purpose, roles and objectives is essential

A high level of cooperation between the Authority and Transpower will help better facilitate implementation of any changes to the Guidelines. Similarly, recognising each other's role and committing to engaging in respectful way will reduce unnecessary conflict and the associated legal and process risk.

The 2014/15 Operational Review was a useful dry-run on implementing changes to the TPM for Transpower and the Authority (albeit at a much lower scale and shorter timeframe than would be required for the 2nd Issues Paper proposals). Both parties learned lessons and it will be important those are applied here, if the Authority decides to amend or replace the Guidelines.

We agree with the Authority[33] that, if it decides to issue new Guidelines, it would be appropriate for Transpower to consult stakeholders as we develop the new Guidelines into a TPM.

### 2.3.2 Removal of an ex ante peak price reduces option value and creates unnecessary risk

We understand the Authority's 'shadow price'[34] thinking. It is novel, but we think it broadly holds only in certain conditions, for example in relation to connection asset investments. In those

[33] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2016, paragraph 12.4,

circumstances customers (i) have accurate information (ii) have the unilateral ability to control the timing and cost of investment, and (iii) internalise the cost and benefits of their actions.

However, we do not believe it holds in relation to shared (interconnection and HVDC) asset investments and therefore cannot provide the signal envisaged by the Authority. The reason it does not hold in these circumstances is that, in real world conditions, information asymmetry, forecast error and coordination ('tragedies of the commons') prevail.

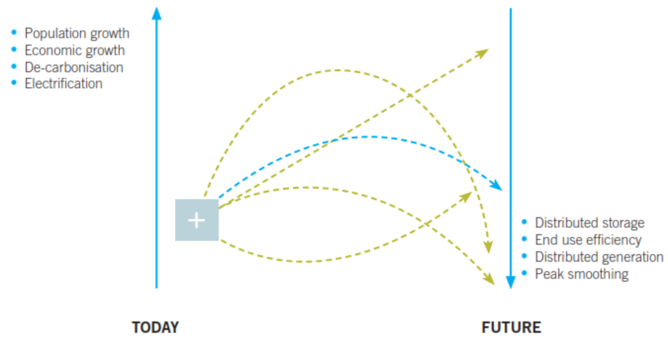
The conditions under which the 'shadow price' logic would work are straightforward to establish – the Authority has alluded to these in its distributed generation consultation, as has Oakley Greenwood in its CBA. These should be tested quantitatively and empirically, before deciding to completely remove ex ante peak-usage prices from the TPM.

Our recent Transmission Tomorrow work has informed our view about future grid demand. It has highlighted the potential for pressures on grid capacity to 'wax and wane' – to grow strongly then to ease. In this context the option value of deferring investment (transmission and generation remote from load) is elevated (suggesting a strong price signal is optimal).

Absent an explicit ex ante price signal, the Authority's proposals will 'over-correct' resulting in an under-signalling of forward looking transmission costs.

Under-signalling could shift us from the blue line to the most parabolic (and regretful) trajectory depicted in Figure 1.

Figure 3: Capacity pressure trajectories (source: Transmission Tomorrow)




Avoiding this over-correction is essential. In this respect, we recognise that the proposal includes the option of introducing an LRMC charge. In our view, if the RCPD is abandoned, an LRMC charge should be mandatory.

This is because, at present, the RCPD price signals are a key component of, if not the main driver for, a proportion of demand response and regional (including distributed) generation. Table 4 shows the high level results of our analysis of the role existing distributed generation and demand response play in meeting the gross peak demand (metered consumer demand).

Table 4: Establishing a picture of 'gross system demand'

| Scenario | Demand (MW) | % above net load |
|---|---|---|
| Net GXP demand | 6200 | 0% |
| Net GXP + DG only | 6730 | 9% |
| Net GXP + DG + DR[35] | 7420 | 20% |

[34] Provided by the combination of nodal prices and the prospective allocation of costs under the Area of Benefit charge.
[35] Based on the 80% EDB sensitivity scenario in Appendix G1.

Scenario 'Net GXP + DG + DR' reflects actual DG injection, demand response observed at the largest direct connect consumers and electricity distribution business (EDB) demand response (at the level indicated by EDBs in an informal survey conducted during the consultation period).

The distributor survey indicates demand is being managed by some 652MW with 625MW in response to RCPD price signals. The demand response reported in Table 4 includes an 80% response from EBD to the RCPD signal and an observed response of 190MW from the large direct connects (690MW in total). We note that some of the response from the direct connects may be influenced by spot prices. Similarly we don't understand the extent to which RCPD price signals are a key component of (or the main driver of) DG availability during peak demand periods.

Appendix G1 contains analysis of DG and load management by Scientia consulting that informed Transpower's work and is the basis for Table 4.

### 2.3.3 To be "durable" the reallocation of sunk costs need to be objectively reasonable and fair

A key aspect of improving durability is addressing perceptions that the TPM is not fair. While fairness is a largely subjective concept we nonetheless consider it should be possible to establish a method that would be perceived as broadly reasonable and fair to an 'impartial bystander'.

To this end, we propose several amendments to the Authority's draft Guidelines to enhance our ability to make any changes to the TPM proposal more durable. For example, we recommend changes that permit:

- Inclusion of as much of the grid as possible in the AoB charge
- Use of 'replacement cost' (rather than 'depreciated historic cost') as an allocator for existing sunk assets.

The purpose of these changes is to help make the AoB time neutral and to avoid the risk of arbitrarily penalising some customers on the basis of asset age. The impact is non-trivial. The Authority has shown that if regions pay for their own post-2004 assets on a DHC basis, but pre-2004 assets continue to be pooled, UNI prices would rise by $94m.

However, if all assets are included, and valued at RC, UNI prices would rise by significantly less. While we consider the latter approach to be more efficient, principled and fair, we recognise and respect that the Authority is the arbiter of durability and we consider the process provides for this.[36]

More generally, we consider that wealth transfers should be minimised but, where necessary to achieve efficiency gains, should be justified by and proportionate to those efficiency gains. This is important for durability but is likely to be violated where (negative) transfers are many multiples of the estimated efficiency gains.

### 2.3.4 Complexity drives implementation costs, timeframes, risk

We commissioned PWC to assess likely costs and lead times for implementing the draft Guidelines.

A key finding of PWC's report was the strength of the link between complexity and cost. In particular, PWC found that costs, elapsed time and risk during implementation are closely related to the complexity of the scenario analysed.

We discuss implementation in Part 1 and below in greater detail in Part 2.5 of this submission. PWC's report is enclosed at Appendix D.

[36] The Authority may refer the proposed TPM back to Transpower and, if still unsatisfied, may determine its own TPM.

## 2.2 Our approach

The Authority is consulting on changes to the way Transpower's costs are recovered from our customers. Changes to the TPM do not directly affect Transpower's profitability.

If changes are carefully thought through, are robust and are implemented in a sensible way then there is the potential to achieve better outcomes for Transpower, our customers, and, ultimately, consumers.

However, if changes are not carefully thought through, are not robust or are not implemented sensibly, then they could adversely impact those parties.

Therefore, we have a particular interest in ensuring, to the extent we can, any TPM changes provide efficient price signals to our customers, are not unduly complex or onerous to implement and operate and are objectively fair and reasonable (and therefore are durable).

### 2.2.1 We have carefully considered the Authority's proposals

Transpower has carefully considered the Authority's proposals.

Our objective is to provide constructive feedback to help the Authority reach a robust, timely decision we are confident would meet its objectives and which we could implement. Consistent with that goal, during the consultation we have:

- Engaged extensively with the Authority bilaterally and via its series of briefings and workshops;
- Spoken with many of our customers and their representatives to understand key concerns; and
- Continued to answer questions and respond to requests for information from the Authority[37] and other stakeholders where able.

### 2.2.2 Distributed Generation Pricing Principles

The effect of the Authority's proposal to remove the distributed generation pricing principles (DGPPs) is to advance the impact of a substantial part of its proposed change to the TPM, namely the removal of the RCPD charge.

We submit separately on the DGPP proposals. In summary:

- We agree with the Authority that, under the current TPM, avoided cost of transmission (ACOT) payments made by distribution businesses under the DGPPs do not accurately reflect the avoided cost of transmission
- This is likely to result in over-compensation by distribution businesses (on behalf of consumers) of distributed generators for the benefits they provide to distribution and transmission networks.
- We are not yet convinced that removing the DGPPs is the correct remedy to this problem and we are concerned this may have unintended consequences. For example, we consider that TPM reforms may obviate the need for major change to the DGPPs.[38]

[37] Pursuant to the agreed ways of working that the Authority and Transpower have been working to.
[38] Though we recognise some change may be warranted, for example to make the DGPPs technology neutral.

- Proceeding with the proposed changes and timetable is risky and may prove counter-productive. For example, Transpower could not establish the planning, economic, commercial or legal frameworks to support the new regime before 1 April 2017.

### 2.2.3 Comments on process

The Authority has gone to great lengths to ensure this review is consultative. We support continuation of this approach and suggest it follow the consultation steps adopted for its 1st Issues Paper. We recommend that the Authority invite cross submissions and consider holding a conference.

These are standard procedural steps for major regulatory changes such as this and we were surprised the Authority did not automatically include these in its plan. We recognise the Authority's wish to conclude this review however consider it would be a false economy to skip important process steps now.

Further, we do not think this would necessarily delay the Authority's final decision but would provide a more robust process that stakeholders could have improved confidence in.

We also suggest the Authority undertake a further short consultation on the draft Guidelines once it has settled its policy and produced revised (draft final) Guidelines. We note that this final step is fairly standard practice for the Commerce Commission and other regulators.

## 2.3 Supporting analysis

To inform this submission and our advance planning for potential changes to the Guidelines we undertook or commissioned a range of technical, economic, legal and operational reviews. In summary:

Table 5 Description and summary of findings

| | Analysis | Description | Key findings |
|---|---|---|---|
| 1 | Economic review (Appendix C) | Axiom Economics reviewed the Authority's proposals (and Oakley Greenwood's cost benefit analysis work for the Authority) | Reservations with OGW's CBA and several of the Authority's proposals. |
| 2 | Implementation costs and timeframes (Appendix D) | PWC assessed likely costs and timeframes for implementing three different reform complexity scenarios. | Lower than for 2012 proposals. Cost and time to implement directly driven by complexity. |
| 3 | Area-of-benefit analysis (Appendix E) | Scientia consulting reviewed the Authority's vSPD application of the AoB charge. We have also begun to explore potential alternative approaches (for 'simplified' and 'standard' AoB charges). | Assumptions and choice of counterfactual drives private benefits result. Ideally would link 'standard' AoB to Capex IM investment test. |
| 4 | Removing RCPD: impacts analysis<br>(Appendix G) | Transpower staff (power systems planning and system operations) conducted a high level analysis of potential implications of removing | 20% 'gross demand' met by demand response and DG.<br>Grid cannot meet gross demand in all areas. Extreme change in DR and DG |

| | Analysis | Description | Key findings |
|---|---|---|---|
| | | 5the RCPD peak price signal.<br>Scientia consulting modelled 'gross system demand' (adding estimated demand response and distributed generation to net GXP level demand). | behavior will affect grid operations, create market constraints with increased opportunities for pivotal behavior by generators. It may lead to load shedding. |
| 6 | Post project review of change to SIMI (Appendix G) | Transpower staff analysed the impact to date of the Authority's decision last year to change HVDC pricing from historic anytime maximum demand (HAMI) to South Island mean injection (SIMI). | Main benefits expected in coldest conditions but to date: plant offered at capacity, up to 62MW and 27GWh generated above prior 'HAMI limits' from 1 Sept 2015 to<br>5 July 2016, costs $2.9m lower. |
| 7 | Price impacts (allocator impacts - Appendix H) | We replicated price modelling by the Authority and gathered data to test the sensitivity of different price scenarios | Choice of allocator a critical determinant of price impact. |

The results of this work have informed our thinking and this submission.

## 2.4 Concerns with the Authority's proposals

In this section we comment briefly on the challenges of transmission pricing and outline several issues that we have with aspects of the Authority's consultation paper and proposals.

We refer also to Part 3 of this submission (and Appendix B – which contains an annotated, amended version of the draft) and to the appended expert reports.

### 2.4.1 No perfect TPM

We recognise that developing a transmission pricing methodology requires managing a number of trade-offs (e.g. efficiency, durability, simplicity, transparency). We consider the 2nd Issues Paper has highlighted some problems with the current TPM, particularly with the relatively simplistic way RCPD charges are set.

However, with some limited exceptions the current TPM is generally acknowledged by stakeholders and our customers as working well. This is reflected in submissions to the 2014/15 Operational Review, and the Authority's consultations. The options which have found most favour are retention of the status quo, or targeted changes to address specific concerns with the TPM. This reflects the fact that:

1. The existing deep connection charge is a cost reflective charge that directly assigns costs for a significant proportion of the grid. Table 6 shows the proportion of transmission assets that are directly assigned to Transpower's customers under the current deep connection charge.

Table 6: Proportion of grid assets directly assigned to Transpower customers

| | Connection | Interconnection | Mixed |
|---|---|---|---|
| Proportion of Substations | 37% | 5% | 58% |
| Proportion of Transformers | 81% | 17% | 1% |

| | | | |
|---|---|---|---|
| Proportion of Switchgear | 62% | 37% | 1% |
| Proportion of Transmission lines | 11% | 82% | 7% |

This demonstrates that the costs of a significant proportion of transmission assets are assigned directly to the customers that use the assets. This is consistent with principles of efficient transmission pricing.

2. While the peak price signal provided by the RCPD interconnection charge may be considered blunt, it has helped to defer transmission investment (as detailed, for example, in the Authority's first Issues Paper).
3. The HVDC charge provides a clear North-South locational signal.

While we recognise that there are equity concerns and the price signals provided by the RCPD and HVDC charges may be too strong we consider the inefficiency to be relatively small. For example, compared to a hypothetically perfectly efficient TPM, as assumed by Oakley Greenwood for the Authority, the level of inefficiency associated with the current TPM equates to 2.5% of revenue for the TPM as a whole (and 0.77% for the HVDC).

We were, consequently, surprised by the Authority's statement that the TPM is "fundamentally inconsistent with the principles of efficient pricing."

We caution the Authority against overstating problems with the status quo. We recognise that this is a natural tendency when making the case for change but, if unchecked, could lead to radical, disruptive change where targeted reform would be more proportionate, carry lower cost and risk and better promote the statutory objective.

### 2.4.2 Concerns with aspects of the Authority's proposal

Our concerns are summarised in Table 7. At this stage we consider:

- The best way to deal with our concerns is through adoption of our simplified, staged alternative. Section 1 sets out our thoughts in this area. Appendix A contains a draft addendum to the existing Guidelines through which these could be achieved.
- Some, but not all, of these concerns could be addressed through changes to the Authority's draft Guidelines. We have suggested a number of amendments to the draft Guidelines (Appendix B) aimed at addressing these where possible, without compromising the policy intent).

**Table 7: Summary of misgivings with the Authority's TPM proposals**

| Misgiving | Comment |
|---|---|
| Scale of the pricing impacts | The Authority's TPM proposals would result in substantial price impacts relative to the prospective efficiency gains the Authority expects would eventuate. This could be made transparent by replicating the price impact analysis in the DGPP consultation. |
| Uncertainty over how robustly benefits can be calculated | There is considerable uncertainty about whether a robust benefit-measurement method can be developed that is fit for transmission pricing purposes. The Authority's experience in applying vSPD reinforces this concern (as do the limited operation of AoB in American jurisdictions).<br><br>The timeframe available for submissions means we cannot confirm we could robustly calculate net positive benefits. |
| Wide range of potential pricing outcomes | The challenges with calculating private benefits go well beyond accuracy. The results are highly sensitive to the assumptions and modelling inputs used – such |

| Misgiving | Comment |
| --- | --- |
| | that the range of outcomes could potentially have an individual customer being determined as a minor or a principal beneficiary.<br><br>These problems are likely to be worse for sunk assets than for new assets. The estimate of benefits from sunk assets depends on assumptions about what would have happened in the past absent the investment, and not just about the future. The counterfactual becomes more hypothetical the older the asset. |
| Potential for increased disputes from application of AoB to each new eligible investment | It would not be possible to codify all elements of the benefit-calculation methodology in the TPM (unless a very simple method is adopted), so Transpower would need to be granted considerable discretion. This would be highly contentious.<br><br>There is a risk stakeholder attention would be diverted from the market benefit assessment, as to whether projects should go ahead, to the question of who benefits and by how much (as this directly impacts on the transmission charge impacts of the project). The sensitivity of the private benefit assessment to input assumptions would only exacerbate this situation. |
| Discriminatory treatment of our customers | We do not support adopting a TPM that discriminates against some of our customers solely (and arbitrarily) on the basis of the age of the assets which supply them. Such an approach seems removed from a service-based or cost-reflective approach, and would not be viable if transmission services were in a workably competitive market. |
| Impact of complete removal of the existing dynamic price signals. | The proposals remove the existing dynamic pricing signals. The RCPD charge signals that increases in peak demand drive transmission investment while the HVDC charge signals investment in South Island generation has longer-term transmission cost implications.<br><br>The 2nd Issues Paper highlights why the proposal could be a problem: “deferring for five years a transmission project with a capital cost of $400 million and operating costs of $20 million per year would save the economy $40 million in net present value terms”.[39]<br><br>We consider that this kind of potential impact is too significant to rely on ‘judgement’ that AoB would act as a proxy for LRMC, rather than hard evidence to support the contention. We note that the combination of DR and DG, as a proportion of peak demand, in each region is:<br><br>• UNI: 9-12%<br>• LNI: 22-28%<br>• USI: 17-30%<br>• LSI: 15-18%[40]<br><br>The significance of this is that the combination of DR and DG equates represents many years organic demand growth in all four regions. This is a relevant consideration for all four regions (and both connection and interconnection investments).<br><br>In relation to the interconnected grid, even a moderate behavioural change in response to modified price signals is likely to bring forward large investment programmes. We have undertaken some work to estimate and quantify potential impacts and, although it is not in a suitable form to include in the submission, we would be happy to brief the Authority on our approach and findings. |

[39] Electricity Authority, Second Issues Paper, Transmission Pricing Methodology: Issues and proposal, 17 May 2016, paragraph 144.
[40] Appendix G1: Scientia Consulting – Embedded generation and gross demand analysis report.

| Misgiving | Comment |
|---|---|
| Impact on the wholesale electricity market and the nature of the 'locational' signal AoB would send to prospective new generation | The arguments for charging generators for interconnection services need to be weighed up against the types of considerations the Authority used in its 2nd Issues Paper to justify applying the residual to load only.<br><br>The Authority's view is that "generation is more likely than load to alter its behaviour if the residual were applied to both. Thus applying the residual charge to generation is likely to result in more costly distortions to generator investment and operation decisions. For example, some submitters have argued that applying the charges to generation would create incentives for generators to inefficiently amend their wholesale offers in order to avoid charges".[41]<br><br>We are concerned the Authority has not assessed (or quantified) potential wholesale electricity market impacts. Our concern is heightened by the nature of the 'locational' signal that the AoB charges would send to prospective generators – essentially areas with post-2004 investments should be avoided. This would mean, for example, that generation investment would be discouraged in the central North Island, even though (or because) transmission upgrades have been undertaken which provide capacity for increased generation in this area. |
| Number of price adjustment mechanisms required | The 'optimisation' and 'marginal savings' adjustments duplicate other mechanisms or could be addressed more directly elsewhere.<br><br>While several of the proposed changes to the prudent discount policy appear warranted and practical to implement we have serious reservations about the efficacy and practicality of the 'plant close down' proposal. For example:<br><br>• The lack of an obvious fit with the institutional competency at Transpower or the Authority (this appears to be a central government economic policy decision)<br><br>• The potential for gaming and double-dipping by sophisticated firms and the risk that the PDP delivers worse, not better outcomes for consumers<br><br>• The likelihood of harming competition and creating moral hazard by favouring some firms over others<br><br>• The fact that, by limiting the scope to the residual, the discount may not be sufficient to secure the desired outcome.<br><br>However, we understand the problem the Authority is trying to solve and will work with it to identify a durable solution.<br><br>A more general concern is the number of 'fixes' the Authority has had to incorporate into its proposal to address anomalies (and, relatedly, to the DGPPs). In our view, a durable TPM should not require such a range of adjustment or price correction mechanisms. |
| Simplicity v complexity | In relative terms, the Authority's proposal is simpler than earlier proposals, and we welcome this. However it remains very complex and intricate, both reducing transparency and practicality. We have genuine concerns about the workability of the proposals and do not consider they can be implemented to the Authority's desired timeframe. |

[41] Electricity Authority, Second Issues Paper, Transmission Pricing Methodology: Issues and proposal, 17 May 2015, paragraph 7.198.

### 2.4.3 Cost benefit analysis

We support the use of quantified cost benefit analysis (CBA) wherever possible. Quantified CBA helps establish the impact of policy or regulatory change and the extent to which it is likely to be in the long-term interests of consumers. It is therefore an important component of the evidence needed to justify policy reform, especially major reform.

As well has establishing the raw net benefit (or net cost) figure, quantified CBA means the Authority's assumptions about how its proposals will impact behaviour are transparent and can be tested.

We commented in depth on the Authority's approach to CBA for its TPM review in our 2013 submission to the TPM review: cost benefit analysis working paper.[42]

#### Misgivings with the Oakley Greenwood CBA

While the Oakley Greenwood work has helped to make some of the Authority's assumptions about the impact of its proposals on behaviour transparent we have a number of reservations about the analysis. We encourage the Authority to revisit this analysis before relying upon it to support a decision.

In relation to Oakley Greenwood's work we see two principal issues:

1. **It assumes the proposed AoB pricing is efficient:** The positive net benefit result from the modelling is essentially an assumption. All inefficiencies that would result from the Authority's proposals are ignored or assumed away.
2. **It models a simplified version of LRMC pricing (rather than AoB or deeper connection):** This is problematic because there is no obvious reason why a 'shadow price' based on future AoB charges would reflect LRMC (AoB and LRMC prices are calculated in different ways).

   Although the modelling does not reveal much about the benefits of AoB or deeper connection it does go some way to demonstrating that simplified LRMC pricing (or a simplified LRMC plus AoB hybrid) might have positive net benefits.

##### *Axiom review of Oakley Greenwood's CBA modelling*

Given our concerns, we asked Axiom Economics[43] to comment on the CBA undertaken by Oakley Greenwood. Axiom's review reinforced our view that it would be necessary to revisit this analysis before relying upon it to support a decision. In particular, Axiom concludes the Oakley Greenwood model does not provide a robust indication of the costs or benefits of the proposal.

Axiom identifies the following key concerns with the Oakley Greenwood CBA:

> It rests on three key foundational assumptions:
>
> - that the AoB charge would provide an efficient *ex-ante* price signal, i.e., that it would provide an accurate and predictable indication to customers of the potential consequences of their actions on Transpower's future costs;
> - that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand; and

[42] Transpower, Submission by Transpower on TPM: Cost - Benefit Analysis framework, 15 October 2013, page 3.
[43] Appendix C: Axiom Economics review of second TPM Issues Paper, section 7.

- that the AoB (and deeper connection) charges that each market participant (e.g., individual generators) would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, e.g., UNI, LNI, USI and LSI.

None of these assumptions hold …

Furthermore, by assuming that the AoB charges would be 'perfectly efficient' (i.e., send an efficient *ex-ante* price signal, and be non-distortionary *ex-post*), the model *must* conclude that future generation and transmission costs would be lower. All it is doing is working out how big this benefit is – which is not an appropriate approach, when carrying out this type of analysis. The modelling of benefits itself also entails many unreasonable input assumptions …[44]

Axiom's report contains a detailed assessment of the Oakley Greenwood CBA. We recommend that the Authority asks Oakley Greenwood to respond to these comments and any concerns raised in other submissions and expert reports.

## 2.5 TPM DEVELOPMENT PROCESS

In this section we outline initial thoughts on the process that, if the Authority decides to amend or replace the Guidelines, Transpower could adopt to implement that decision.

We thought it would be helpful to outline our thoughts at this stage. We have had initial discussions with the Authority and expect these to continue as it formulates its final decision.

### 2.5.1 CONSULTATION

Several stakeholders have asked us about the process we would adopt, if the Authority amended or issued new Guidelines, to develop a revised TPM. All expressed a view that, for the durability of the TPM, Transpower should follow a transparent and consultative process. The Authority has expressed similar views.[45]

The Authority indicated the process for the 2014/15 TPM Operational Review could provide a starting point for the development of Guidelines into a TPM. We propose to work with the Authority on a TPM development process. It will be important that this provides a realistic timetable for Transpower to develop its proposed new, or revised, TPM, and provides for consultation and engagement with stakeholders.

Depending on the nature of the Authority's final decision, these timeframes could be substantially longer than the Authority has assumed, based on implementation by 1 April 2019. The Authority has experienced considerable challenges in developing its proposals and we don't anticipate the task would be any easier for Transpower.

### 2.5.2 IMPLEMENTATION COSTS AND LEAD TIMES

For the first Issues Paper we asked PWC[46] to cost the Authority's specific proposal and to estimate implementation lead times. We wanted to replicate this analysis for the latest proposals.

One challenge with less prescriptive guidelines is sizing the implementation task. That uncertainty affects both the initial TPM development task, its implementation into pricing processes and systems, its operational implementation and the future operation of the revised TPM.

[44] Axiom Report, Second TPM Issues Paper, July 2016, Executive Summary, attached at Appendix C.
[45] Electricity Authority, Second Issues Paper, TPM: Issues and proposal, 17 May 2016, paragraph 12.4,
[46] PWC audits Transpower's application of the current TPM so is familiar with the systems, process controls (etc) used to generate prices.

In light of this we asked PWC to assess three different TPM change scenarios to help with the Authority's options assessment and inform the section 54V[47] process.

## PWC implementation study

PWC analysed low, medium and high complexity scenarios. They assessed current state conditions and surveyed the impacted parties within Transpower. They then used PWC's standard enterprise cost estimation tools to define and cost implementation stages. Their high level findings were:

- Relative to the methodology proposed in 2012, Transpower faces a larger up-front TPM development task but simpler system implementation[48]
- Costs and timeframes for implementation are correlated to complexity level but accurate estimates remain elusive due to the degree of uncertainty at this stage
- All 2016 scenarios had lower total costs than the 2012 proposals but elapsed time for implementation is similar for the medium and high complexity scenarios.

Table 8 and Figure 4 taken from PWC's report demonstrate these points. Table 8 presents implementation cost[49] for the three complexity scenarios and includes the Authority's 2012 TPM proposals.

**Table 8: Summary of implementation cost estimate by stage**

| *Scenario* | *TPM development ($M)* | *Systems implementation ($M)* | *Hard-/Software & Support ($M)* | *Operational Implementation ($M)* | *Ongoing costs ($M)* | *Systems implementation & 5 year operation ($M)* |
|---|---|---|---|---|---|---|
| *2012 Proposal* | *not assessed* | *12.5-13.4* | | *1.1* | *0.8* | *16.8-17.7* |
| High complexity | 4.3 | 8.2 | 1.5 | 1.5 | 0.8 | 14.4 |
| Medium complexity | 3.2* | 2.0-4.0* | 0 | 0.7 | 0.4 | 4.5-6.5 |
| Lower complexity | 2.8* | 0.5-2.0* | 0 | 0.6 | 0.3 | 2.3-3.8 |

Although as noted above, it has been difficult to size the TPM development and implementation task we consider the estimates arrived by PWC provide reasonable bounds for the range of complexity scenarios. We consider

1. The 'high complexity'scenario most closely our understanding of the Authority's proposal.
2. The 'medium complexity' scenario appears closest to simplified, staged approach that we outline in Part 1 for cost estimation purposes (though not in terms of implementation timings).
3. The 'medium complexity' scenario also broadly reflect the modified draft Guidelines contained in Appendix B.

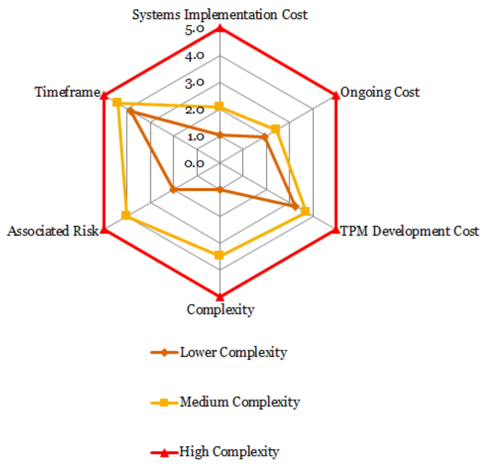
Figure 4 plots the three complexity scenarios against key cost, risk and timeframe parameters.

[47] The Commerce Commission excluded costs for TPM implementation from Transpower's individual price path (IPP) on the Authority's recommendation on the basis that under Section 54V of the Commerce Act the Authority can request that the Commerce Commission revise Transpower's IPP to provide for additional costs imposed by the Authority's decisions.

[48] As a cross check on our assessment of the *TPM development* element we requested but have not received information from the Authority on the cost to date of its TPM review project.

[49] Estimates exclude lifecycle driven replacement of Transpower's existing pricing systems and 'Zemindar' pricing engine.

**Figure 4: Implementation scenario analysis**

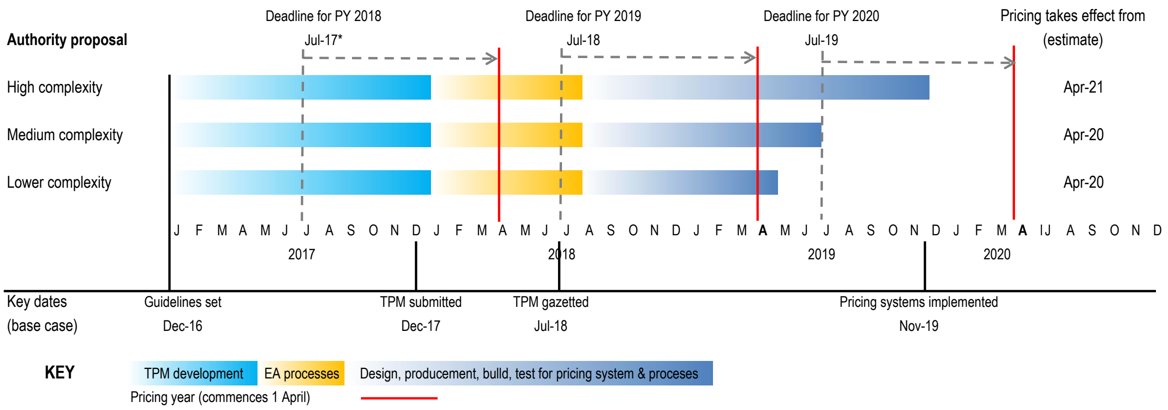



Key TPM implementation elements

1. **TPM development:** the economic, technical and legal process of developing the new TPM
2. **Authority processes:** [as specified in the Code]
3. **System implementation:** designing and building new systems and processes
4. **Operational implementation:** applying those new systems and processes for the first time
5. **Ongoing operation:** of the new TPM regime.

PWC's report also contains an assessment of the likely sequencing of tasks, dependencies and elapsed time for implementation. Based on our assessment of PWC's report and the process the Authority is expected to follow we estimate that the Authority's proposals are highly unlikely to flow through into prices until at least April 2020, possibly April 2021, if a 'high complexity' approach is adopted.

Figure 1 (replicated below for reference) shows PWC assessment of the elapsed time to implement the Authority's proposals under different complexity scenarios.




* Deadline for completion of **major changes** to the TPM systems. Prices are notified to customers in November to take effect for the next pricing year (PY starts 1 April each year). This allows distributors to reflect transmission pricing in their own tariffs and in turn to notify retailers. This lead time also permits necessary customer consultation on the most complex aspects (connection charges), external audit and approval by Transpower's Board.

The main conclusion of PWC's work is that the elapsed time to implement the Authority's proposal is likely to be approximately 34 months. In other words, the Authority significantly underestimates the time (and cost) involved in implementing a major TPM change project.

# 3 PART 3: REVIEW OF DRAFT GUIDELINES

Although we have suggested an alternative TPM reform package that we consider to be proportionate to the problems the Authority has identified with the TPM, we respect the Authority's role and will continue to offer support as it formulates its decision.

If the Authority decides to change or replace the Guidelines, we will do our best to implement those changes in a TPM that best promotes the long-term interests of consumers.

To that end, in this section we asked ourselves: if the Authority's proposals are adopted, what changes, if any, should be made to the draft Guidelines?

## 3.1 Introduction and objective

Based on a predominantly technical, clause by clause, review, we include a mark-up of the draft Guidelines with amendments annotated. The objective of our amendments is to:

1. Clarify or improve the drafting of the Guidelines but not alter the policy intent;
2. Remove potential conflicts between different parts of the Guidelines;
3. Achieve an appropriate balance between the Authority's role in establishing the Guidelines and Transpower's role in converting the Guidelines into a Methodology – we discuss this point in more detail below;
4. Improve our ability to meet the Authority's objectives – including to:
   (i) improve the likelihood the AoB charges can be determined on a practical and defensible basis;
   (ii) mitigate unintended impacts on the wholesale market; and
   (iii) limit the number and scope of price adjustment mechanisms that are needed – we discuss this point in more detail below.

We have also suggested changes to ensure the AoB charges meet the beneficiaries-pay criteria specified in the Authority's TPM decision making economic framework (DMEF), and to improve the interaction between the AoB, residual and potential LRMC charges.

## 3.2 The role of the Guidelines vs development of the TPM

We recognise that no bright line delineates the boundaries between the Guidelines and the TPM.

However, we consider that care is needed to ensure the Guidelines direct Transpower by laying out clear principles for the TPM but does not unduly foreclose design options.

At present there are aspects of the draft Guidelines where discretion granted in one place is potentially hampered by more restrictive requirements elsewhere in the Guidelines. For example, the draft Guidelines leave it to Transpower to determine the method for calculating benefits, but prescribes (and limits) the assets which would initially be treated as eligible investments.

The problem is that while the eligibility limit may make sense for some benefit methods (such as vSPD-based approaches, where complexity and the modelling requirements could make applying AoB to an expanded range of investments problematic and onerous), it may not under other methods. For example, under other potential benefit method options it may be better to apply a single, standard, method to all transmission investments and minimise reliance on residual charges. Such approaches could produce more cost reflective prices, but are not currently available.

These types of issues could be resolved through some simple changes to the proposed TPM Guidelines. For example, by specifying that the list of eligible investments is a minimum (allowing Transpower to include additional investments), and providing greater flexibility around application of a standard versus simplified method.

By way of further example, we consider it would be better to specify that the Residual Charge is required to be set in a way that, to the extent practicable, is as fixed (unavoidable) and 'incentive-free' as possible, and leave the determination of the allocator to be adopted (be it physical capacity, as currently prescribed, or some other allocator) to the subsequent stage when the methodology itself is designed.

If the Guidelines are to specify the method by which the residual charge is allocated then, in our view, the Authority should undertake further analysis to demonstrate the options presently in the proposed Guidelines are superior to others, such as historic RCPD (proposed by Trustpower), which have been ruled out – albeit simply because it is not a form of capacity. [50]

## 3.3 LRMC AND AOB

We consider that LRMC revenues should be able to be attributed to the AoB (rather than just to the residual).

The Authority has noted LRMC charges can "efficiently defer new investment … by applying an additional charge for the use of existing assets to limit use of those assets" (emphasis added).[51]

The problem that this creates is that if existing assets are eligible investments the Authority's proposals could result in double-recovery, violating the principle that charges should not exceed stand-alone cost.[52] That is because a grid-user (or users) could pay the full cost of existing eligible investments, an LRMC charge which reflects the future expected cost of the next investment, and then the full cost of the next investment through the future AoB charges.

The current drafting of the proposed Guidelines mean that, if Transpower determined LRMC should be adopted, the TPM could violate the beneficiaries-pay principle that no party should pay more for an asset or service than the benefit they receive. It could also violate the principle that prices should be capped at stand-alone cost. This would make it more difficult for Transpower to conclude that introduction of LRMC would be desirable, even if it resulted in substantial dynamic efficiency improvements.

## 3.4 TRANSMISSION PRICE ADJUSTMENT MECHANISMS

The draft Guidelines contain three mechanisms for adjusting the transmission charges calculated under the proposed AoB charge:

- An optimisation adjustment that would be used in limited circumstances only;
- A "marginal savings" adjustment mechanism; and

[50] As discussed at the Electricity Authority's Wellington workshop on the 2nd Issues Paper.
[51] Electricity Authority, Second Issues Paper, Transmission Pricing Methodology: Issues and proposal, 17 May 2016, paragraph 7.305.
[52] Again, this highlights the importance of distinguishing between cost allocation and charging mechanisms.

- Extensions to the Prudent Discount Policy including a significant new policy where a discount would apply if there is a material risk that a customer might shut down its New Zealand based plant, absent a discount to its transmission charges.

We understand the problems the Authority is trying to solve in proposing these mechanisms. However, we consider there are issues with each of the three proposals.

Our preference is to avoid or mitigate the potential need for these additional mechanisms through the design of the TPM and/or moderating the extent to which any changes to the TPM result in wealth transfers or price shocks. Each of the proposed adjustment mechanisms is discussed below.

### 3.4.1 Optimisation adjustment mechanism

We consider that the optimisation adjustment provision in the proposed Guidelines should be removed. We recommend that this is replaced by a cap that limits AoB charges to aggregate positive net benefits (amendment to clause 6).

The role of optimisation could be seen as broadly similar to applying the DMEF's principle that beneficiaries-pay charges should be capped at "the lesser of the charge which will fully recover the costs of the grid being paid by beneficiaries and the anticipated (ex-ante) value to them from the services provided by the grid".[53,54]

Under both optimisation and a benefit-cap, grid-users would pay AoB charges for assets to the extent they are 'used and useful' but in quite different ways:

- Optimisation reflects a 'cost-reflective' approach, adjusting the asset value from RC (or DHC) to Optimised RC (or Optimised DHC)
- A benefit-cap reflects a 'service-based' approach, adjusting the charges to reflect the benefit (or value) grid-users receive from an asset.

If the AoB charges are to satisfy the DMEF then they would need to be capped at the benefits the AoB customers receive, which should obviate the need for optimisation.

This approach also recognises that the benefit grid-users receive from an asset can be higher or lower than their optimised and non-optimised values. In other words, it reduces the risk that a customer might (a) face prices in excess of the benefit they received and (b) be able to transfer costs to other customers (in circumstances where benefits exceed non-optimised AoB charges).

We also note that:

1. Past experience and our preliminary assessment of how we might undertake an optimisation process indicates that this is a significant, costly and distracting task
2. Optimisation is usually applied under replacement cost-based valuation approaches rather than historic cost valuation approaches
3. The proposed optimisation rules appear arbitrary and limited. For example, optimisation would not be permitted where the reduction was due to multiple disconnections or where Optimised RC is, say, 81% of the RC for the asset.

[53] Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, Consultation paper, 26 January 2012, paragraph 18.
[54] Under the proposed new TPM Guidelines, the AoB charges do not apply a 'benefit-cap'. Clause 6 requires "The TPM must include an area-of-benefit charge that recovers the full cost of each asset (excluding any connection asset) that is included in an eligible investment".

### 3.4.2 "Marginal savings" adjustment mechanism

We consider that the proposed "marginal savings" adjustment mechanism (clause 10(f)) should be removed. This is because:

- Consideration of 'transmission alternatives' is explicitly provided for by the Commerce Commission's Capex IM; and
- We have concerns about workability of the 'marginal savings' mechanism, and risk of negative unintended consequences.

We consider that the Authority's hypothetical example helps to demonstrate the problems with this proposal. For example, it highlights that market participants could have incentives to change their behaviour in order to reduce their share of calculated benefits.

In the hypothetical example, customer A has a distributed generation option which means Transpower only needs to invest $9m (and customer A's share of the benefits is 20%). The hypothetical example anticipated customer A would use the clause 10(f) (i) mechanism to commit to the distributed generation, and receive a discount of $1m, resulting in a charge of $3m.

There are a number of problems with this example, including:

1. Suppose there is an identical Customer B. Under the Authority's interpretation of the hypothetical example, Customer A, who credibly commits to a load reduction, would pay $3m, but Customer B who doesn't do anything would only pay $1.8m.
2. If Customer A goes ahead with the distributed generation, so the $10m project is not needed, but does not initiate the clause 10(f)(i) provisions their AoB charge would be $1.8m (not $3m) – their incentive would be to avoid activating the clause 10(f)(i) provisions.
3. There is nothing in clause 10(f) (i) that requires, if the provisions are applied, that the AoB method would result in a $3m charge. Given the AoB method would set the charge at $1.8m, an adjustment to reflect any marginal saving would be a discount of up to $1m off the $1.8m (not $1m off a share of the benefit of an investment that never went ahead) i.e. Customer A could end up paying $0.8m.

Section 3 of the Axiom report (Appendix C) discusses economic and workability problems with this proposal. We agree with Axiom's assessment.

### 3.4.3 Prudent Discount Policy

In addition to its current scope, we consider it reasonable for the Prudent Discount Policy (PDP) to apply where:

1. It would be "privately beneficial for a load designated transmission customer to build generation to disconnect from the grid" (clause 36);
2. If transmission charges exceed the stand-alone cost of supplying a customer (clause 40); and
3. To set a floor for the PDP at incremental cost (clause 41).

#### Serious misgivings about plant closedown proposal

While we understand what the Authority is trying to achieve with this proposal, we have serious misgivings about the workability of the proposal to extend the PDP to situations where "there is a material risk that transmission charges would cause the direct consumer [or the distributor's customer] to close down its New Zealand plant". We outline these below.

Our preference is for the plant closedown PDP provisions (clauses 37 to 39) to be reconsidered and removed.

### *Reservation 1: Institutional competency*

We are concerned that we do not have the knowledge or expertise to safely make judgements about whether "there is a material risk" transmission charges would cause the customer to close down, "the customer's business profits have been heavily affected by market conditions", and the customer "has taken reasonable steps to remain viable as a going concern, including taking significant steps to eliminate unnecessary costs".

With respect, we do not believe the Authority does either. Transpower and the Authority would face substantial information asymmetries that would make this assessment difficult.

### *Reservation 2: Gaming risk*

There is a risk the discount could be applied where a customer has gamed the PDP regime by threatening to close down to reduce their transmission costs but has no intention of doing so. This risk means the proposed PDP extension, while well meaning, could have the effect of raising transmission charges to other customers relative to those they would face if it did not exist. In other words, the opposite of what is intended (and the $10m benefit suggested in the cost benefit analysis).

We also note the potential risk of (i) 'double-dipping' (a customer applies to both Government and Transpower (or the Authority) for discounts or subsidies) and (ii) being viewed as a form of trade protection or export subsidy.

### *Reservation 3: Competition effects, moral hazard*

The potential impact on competition would also need to be considered. Where the customer competes with NZ-based firms, applying a PDP discount could (i) introduce competitive distortions (ii) reward firms for making poor choices while penalising the firm's competitors who have made prudent commercial decisions (capital structure, business and product diversification etc) and (iii) run the risk of 'privatising profits while socialising losses'. These are all classic problems with trade protection policy.

### *Other comments*

The Authority has suggested the need for these PDP provisions arise "because the residual charge – being spread across all load customers – has little relationship to the services each customer receives from the transmission system or the incremental costs they impose on the transmission system" and "these concerns will decline over the long term as grid services transfer out of the residual and into the area-of-benefit charge".[55]

We do not consider this to be correct. The single biggest driver for use of these proposed new PDP provisions is likely to be a subset of distributers and direct consumers facing (indicative) transmission charge increases totalling $142.6m per annum. This is principally driven by the AoB charges for interconnection assets and the HVDC.

We note that, while AoB is based on private benefit:

1. The AoB charge is not capped at private benefit; and

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[55] Electricity Authority, Transmission Pricing Methodology: Issues and proposal, Second issues paper, 17 May 2016, paragraph 17.

2. A customer can both receive substantial private benefits from an eligible investment and not be financially viable as a going concern.

Linking of AoB charges to private benefit does not act as a mechanism to avoid the clause 37 and 38 situations arising. We note, though, our proposal that clause 6 of the Guidelines be amended to cap the AoB charges at the lower of full cost and aggregated benefits would partially mitigate the impact of the AoB charges.[56]

If the proposed PDP extension in clauses 37 to 39 are retained some additional provisions should be included. We cover these in our amendments to the EA's guidelines at Appendix B.

[56] Appendix B: Track change version of the Authority's proposed TPM Guidelines.

# 4 APPENDICES

## APPENDIX A: DRAFT ADDENDUM TO THE TPM GUIDELINES

This draft Addendum outlines how Transpower suggests the simplified, staged approach described in this submission could be given effect to.

We note that this is our first attempt at expressing the proposal in Code form and expect it could be improved after discussion with the Authority and stakeholders.

## Addendum to the Guidelines for development of the Transmission Pricing Methodology

## Published under clause 12.83(b) of the Electricity Industry Participation Code 2010 on [insert date]

**Introduction**

1. These guidelines are an addendum to the existing transmission pricing methodology (**TPM**) guidelines, published by the Electricity Commission under rule 6.2 of section IV of part F of the Electricity Governance Rules 2003 on 24 March 2006, and are published by the Electricity Authority (**Authority**) under clause 12.83(b) of the Electricity Industry Participation Code 2010 (**Code**).

**Interpretation**

2. In these guidelines, unless the context otherwise requires—

   (a) the following terms have the meaning given to them in the Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2, including each amendment to that determination, in force on the date of these guidelines:

      (i) commissioning date:

      (ii) completion date:

   (b) **charge** means a charge under the TPM:

   (c) **future high value investment** means an interconnection investment—

      (i) with a commissioning date or completion date on or after the commencement of the TPM; and

      (ii) valued at $20 million or more at its commissioning date or completion date:

(d) **load designated transmission customer** means a designated transmission customer that is a distributor or direct consumer:

(e) **Transpower** means Transpower New Zealand Limited in its capacity as a grid owner:

(f) any other term that is defined in the TPM in force on the date of these guidelines or Part 1 of the Code and used but not defined in these guidelines has the same meaning as in:

(i) the TPM in force on the date of these guidelines; or

(ii) if not defined in the TPM, Part 1 of the Code:

(g) clause references are to clauses of these guidelines.

3. These guidelines are to be read together with the existing guidelines, and these guidelines will prevail to the extent there is any conflict with the existing guidelines.

## Purpose

4. The purpose of the TPM, consistent with clause 12.78 of the Code, is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated in accordance with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

## Simplified area-of-benefit charge for interconnection investments in a region

5. The existing postage stamp charge for existing and new interconnection assets and related transmission alternatives (**interconnection investments**) must be replaced with a simplified area-of-benefit charge.

6. The simplified area-of-benefit charge for an interconnection investment must be allocated to load designated transmission customers in the region or regions where the investment is located (but, in the case of multiple regions, need not be allocated to all of the regions, to the regions equally, or to the regions proportionately based on location).

7. For the purposes of clause 6 there must be no fewer than the existing four regions (Lower North Island, Lower South Island, Upper North Island and Upper South Island).

## Two-part allocation of simplified-area-of-benefit charge for a region

8. The existing RCPD method for allocating the interconnection charge must be replaced with a two-part allocation of the simplified area-of-benefit charge for a region — a peak-usage charge and a residual charge.

9. The allocation of the peak-usage charge for a region must be based on long-run marginal cost (**LRMC**), or be LRMC-like, and must—

(a) be designed to promote the efficient use of grid assets that are not connection assets, so as to efficiently defer or avoid grid investment; and

(b) complement or augment, but not duplicate, the price signals provided by other charges and nodal energy pricing.

10. The residual charge for a region must recover the part of the simplified area-of-benefit charge for the region not recovered through the peak-usage charge for the region.

11. The method for allocating the residual charge for a region must minimise or mitigate—

(a) potential distortion or inefficiency from recovery of the residual charge (that is, the allocation must be as fixed or unavoidable as practicable); and

(b) the extent to which undue price shocks arise from the adoption of the residual charge.

## Additional components

12. The TPM must include any or both of the following additional components if, in Transpower's opinion, their inclusion is practicable and consistent with the requirements of clause 12.89 of the Code—

(a) replacement, or partial replacement, of the simplified area-of-benefit charge for a future high value investment with a standard area-of-benefit charge that is paid by designated transmission customers assessed as likely to benefit from the investment, with the charge allocated in proportion to the positive net benefits they are expected to receive from the investment, or a proxy for those positive net benefits:

(b) a locational charge that is paid by generation designated transmission customers and signals the impact of generation location decisions on grid investment.

## Transition

13. The TPM may provide for the phasing in of the changes required by these guidelines over a period or periods from the commencement of the TPM.

14. The changes to the TPM required by these guidelines may be introduced into the TPM on a phased basis, whereby:

(a) the changes to the TPM required by clauses 5 to 7 are introduced first; and

(b) the changes to the TPM required by clauses 8 to 11 are introduced second; and

(c) any changes to the TPM that may be required by clause 12 are introduced subsequently.

# APPENDIX B: PROPOSED AMENDMENTS TO DRAFT TPM GUIDELINES

[This appendix contains an annotated track-changes version of the Authority's draft TPM Guidelines. Please refer to separate document.]

## APPENDIX C: AXIOM ECONOMICS TPM REVIEW REPORT

[This appendix contains an economic review by Axiom Economics, commissioned by Transpower, of the Authority's proposals. Please refer to separate document.]

## APPENDIX D: PWC IMPLEMENTATION REPORT

[This appendix contains an assessment of costs and timeframes by PWC, commissioned by Transpower, associated with implementation of the Authority's proposals. Please refer to separate document.]

## APPENDIX E: SCIENTIA CONSULTING TECHNICAL REVIEW OF VSPD MODELLING

[This appendix contains a technical review by Scientia consulting, commissioned by Transpower, of the vSPD version of the Area of Benefit charge. Please refer to separate document.]

# Appendix F: Disaggregation of "HVAC overhead" TPM category

In its consultation on changes to the TPM, the Authority identified that the TPM cost category "HVAC overhead" amounted to $198m for pricing year 16/17 and explained that this category contained unallocated operating costs and corporate overhead.[57]

The table below is provided to assist understanding of the TPM category "HVAC overhead".

Table 9 HVAC overhead disaggregation

| | Category | Description | $ (m) |
|---|---|---|---|
| **Controllable operating expenditure** | Maintenance support | Includes non-field functions supporting the maintenance activities for the operate/maintain phase of the asset life cycle such as performance management and maintenance auditing. (Includes Grid Performance division, excludes grid operating centres) | 16.6 |
| | Network operations & control | The functions included in operating the control centres functions as well as those additional activities required to ensure the safe, reliable and efficient operational management of the grid. (Includes Grid Operating Centres and System Operation costs related to transmission operator function) | 13.2 |
| | Asset Management Support | Activities required to support the strategic development and ongoing asset management of the network (Includes Grid Development division, Grid Projects division and Customers and Environmental groups division). | 25.8 |
| | IST Operations | Information Service & Technology costs associated with supporting the operation of the grid. (Includes IST Operating costs plus costs for IST division) | 61.6 |
| | Corporate support | Activities encompassing the support activities required to ensure adequate and effective corporate governance, people support and management, pricing, regulatory support and management, and corporate accommodation costs | 30.1 |
| | **Total controllable operating costs** | | **147.3** |
| **Non controllable operating expenditure** | Levy | Electricity Authority and Commerce Commission levies. | 8.6 |
| | Local body rates | Local body rates | 10.1 |
| | Insurance | Insurance costs related to the grid | 7.4 |
| | Network support | Cost associated with non-network solutions as cost effective alternative to network investment | 1.7 |
| | Pass-through and recoverable wash-up | Under or over recover from previous years | 2.1 |
| | **Total Non-controllable operating costs** | | **29.9** |
| **IRIS** | **Incremental rolling incentive scheme** | Regulatory incentives from RCP1 (Grossed up for tax) | **21.2** |
| **Total HVAC overhead** | | | **198.5** |

[57] TPM 2nd Issues and proposals consultation paper, page 122

# APPENDIX G (AND G1): IMPLICATIONS OF REMOVING RCPD SIGNAL

This appendix summarises analysis undertaken by Transpower and our adviser to understand the potential implications of removing the RCPD peak price signal.

## Introduction

To begin to understand the potential impact of a reduction in the incentives stemming from the current RCPD signals to manage peak demand with distributed generation (DG) and load control we:

1. Analysed DG and load control data to help understand gross system demand
2. Undertook a high level review of:
    i. Grid investment; and
    ii. known security issues in three regions.

In addition, Transpower's system operations division reviewed changes in South Island generation offer and dispatch patterns since 1 September 2015 to assess any impacts from the recent change in HVDC charging. For the avoidance of doubt, this is included for information and is unrelated to consideration of changes to RCPD.

We summarise the approach and findings below.

## 1. Analysis of DG and load control data to help understand gross system demand

[Please refer to separate document – Appendix G1: Scientia Consulting – gross demand report]

## 2. High level review of security impacts in three regions (UNI, USI and LSI)

### Security impacts

In the time available we were unable to undertake detailed system security studies. Rather than perform specific studies, we used previous studies and reports. For this assessment, we used the 2014 System Security Forecast (SSF)[58,] (as revised) to identify current loads and applicable regional load issues.

#### *Northern North Island (Huntly north)*

The existing regional load limit for winter 2016 is 2279MW. This is assuming all grid assets and grid connected generation is in service except one of the two 248MW units at Huntly.[59]. This limit assumes 79MW of embedded generation output (Glenbrook 59MW and Ngawha 20MW).

- The peak winter demand in 2015 was 2150MW which was below the regional load limit. During the 6 system winter peaks last year, the average embedded generation in the Northern North Island, including Te Uku, was 155 MW.
- The expected peak forecast for winter 2016 is ~2154MW but this includes the effects of historic load control

[58] https://www.systemoperator.co.nz/documents/reports/system-security-forecast

[59] This is a representational operational planning study for the region. The absence of a unit at Huntly is representative of a number of asset outage scenarios (grid and generation).

- The prudent, P90, demand forecast for the winter of 2016 is 2347MW

In summary, we expect the 2016 winter demand to be met in the region through participant response to energy and transmission prices. In a scenario without RCPD based transmission prices there would seem to be little incentive for Northern North Island distributors to utilise DR at their disposal. Absent RCPD based transmission prices, demand in the region could easily be 100MW higher, possibly necessitating the need for administrative, rather than price based, demand management.

### *Upper South Island (Timaru and Tekapo A north)*

With all grid assets and grid connected generation in service and without any DG, the USI Voltage Stability limit is 1220MW.

After load control within the region, the winter 2015 peak demand in the USI was 1068MW. The average DG output in the top 5 peaks of 2015 was 97MW.

- The expected 2016 winter peak demand forecast, including load control, is 1077MW.
- The prudent peak demand forecast is 1170MW.

This indicates that without DG during peak demand periods, the winter peak load could be supplied with all equipment in service, although market voltage stability constraints would be expected to bind to ensure sufficient wholesale market generation is dispatched to manage the USI voltage stability limits.

In summary, we expect the 2016 winter demand to be met in the region through participant response to energy and transmission prices. In a scenario without RCPD based transmission prices there would seem to be little incentive for Upper South Island distributors to utilise DR at their disposal which would necessitate the need for administrative, rather than price based, demand management.

### *Lower South Island (Tekapo B and the Waitaki River south)*

The Lower South Island winter 2015 peak demand was 1103MW. This load is net of an unknown level of load control. The output of DG in the region at time of peak was ~85MW.

- The expected 2016 winter peak demand forecast, including load control, is 1218MW.

Most, if not all, operational complexity associated with meeting demand in this region stems from transmission limits within the region, typically south of Roxburgh, when generation in Southland, principally Manapouri generation, is low. DG at Waipori, which participates in the wholesale market, can and does assist with the management of constraints in the region.

In summary, we expect adequate wholesale market generation (including Waipori generation) will be dispatched in the region to enable the 2016 winter demand to be met. In a scenario without RCPD based transmission prices there would seem to be little incentive for Lower South Island distributors to utilise DR at their disposal. In such a scenario if any demand increase arising from the absence of DR could not be met by local wholesale market generation it would necessitate the need for administrative demand management.

## 3. Analysis of South Island generation offer and dispatch since changes to HVDC pricing in September 2015.

We have undertaken an initial ex post assessment of recent changes to the incentives provided by the HVDC charge. For the avoidance of doubt, this is included for information only; it is unrelated to consideration of changes to RCPD.

The change in methodology for allocating HVDC costs to South Island generators from HAMI (historic anytime maximum injection) to SIMI (South Island mean injection) has impacted the wholesale electricity market.

The previous HAMI charge, which was based on a certain number of peak injections over a given period, created an economic incentive to withhold generating capacity. Changing to the SIMI charge, which is an energy charge, removed this incentive from 1 September 2015.

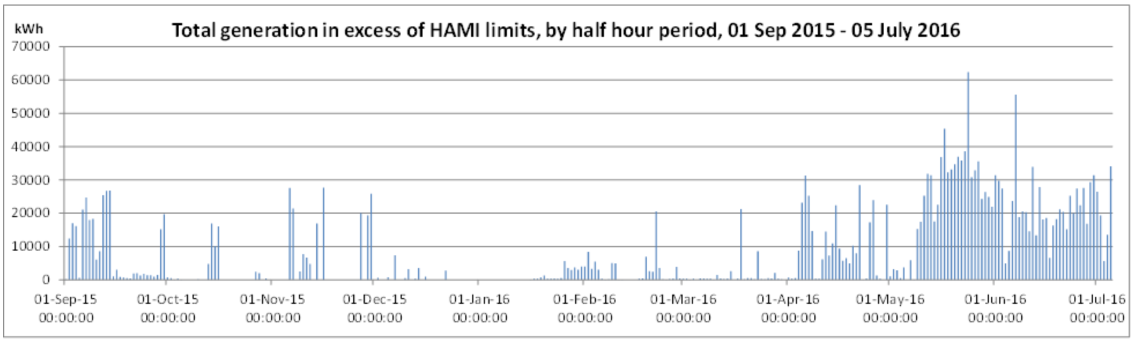
Since 1 September, offered capacity has increased by up to approximately 180 MW[60]. To date, up to an additional 62 MW has cleared, resulting in approximately 27 GWh of generation above the previous implied 'HAMI limits'. This has allowed the dispatch of South Island renewable generation which has displaced higher cost North Island thermal generation.

It has resulted in:

- An estimated saving of $2.9 million in production costs – the cost of cleared offers, assuming offer prices represent the marginal cost of supply.
- An estimated $65 million reduction in cost to purchasers (and a commensurate reduction in payments to suppliers), as cleared prices have reduced significantly.

All things being equal, we would expect total savings to approximately double by the end of winter, and similar savings to be attained in future years. The graph below shows the utilisation of previously withheld South Island capacity between 01 September 2015 and 05 July 2016. Each bar shows the half hourly generation in excess of previous implied 'HAMI limits' – the half hour average generation above which a generator would be allocated a higher proportion of future HVDC charges.

**Figure 5: Utilisation of previously withheld South Island Generation capacity, 01 September 2015 – 5 July 2016**




[60] This is at the 3 most HAMI-constrained SI generators (Benmore, Clyde and Roxburgh). The aggregate increase in offers from these three stations varies depending on plant outages and other constraints.

## Appendix H: Impact of allocator selection

The table below demonstrates the pricing effect in percentage terms of different allocators, applied at a national level, on Transpower's customers. Data is from Capacity Measurement Period (CMP) 1415 for RCPD and AMD, and from 2015 calendar year for median demand.

Note: Using the same allocator at a sub-national level will yield different results.

Table 10: Effect of allocator choice on residual charge distribution

| Customer share of residual charges by allocator | | | | |
|---|---|---|---|---|
| **Customer** | **RCPD** | **Net AMD** | **Gross AMD** | **Median Demand** |
| Alpine Energy | 1.71% | 1.87% | 1.81% | 2.14% |
| Aurora Energy | 3.05% | 3.14% | 3.62% | 2.73% |
| Buller Electricity | 0.18% | 0.23% | 0.30% | 0.24% |
| Central Lines | 0.32% | 0.24% | 0.30% | 0.31% |
| Cobb Power | 0.00% | 0.00% | 0.00% | 0.00% |
| Contact Energy | 0.01% | 0.31% | 0.45% | 0.02% |
| Counties Power | 1.62% | 1.39% | 1.51% | 1.48% |
| Dongwha Patinna | 0.12% | 0.11% | 0.15% | 0.15% |
| Eastland Network | 0.85% | 1.29% | 0.60% | 0.78% |
| Electra | 1.02% | 1.25% | 1.06% | 0.80% |
| Electricity Ashburton | 0.62% | 2.07% | 2.27% | 1.17% |
| Electricity Southland | 0.04% | 0.04% | 0.60% | 0.03% |
| Fonterra Todd Cogeneration | 0.00% | 0.06% | 0.15% | 0.00% |
| Genesis Energy | 0.00% | 0.08% | 0.30% | 0.08% |
| Horizon Energy Distribution | 0.37% | 0.80% | 1.06% | 1.25% |
| KiwiRail | 0.14% | 0.51% | 0.45% | 0.13% |
| MainPower New Zealand | 1.56% | 1.61% | 1.51% | 1.76% |
| Marlborough Lines | 1.01% | 0.87% | 0.91% | 1.03% |
| MEL (Te Apiti) | 0.00% | 0.01% | 0.00% | 0.00% |
| MEL(Westwind) | 0.00% | 0.01% | 0.00% | 0.00% |
| Meridian Energy (incl. MWTK GG) | 0.01% | 0.30% | 0.45% | 0.02% |
| Methanex New Zealand | 0.10% | 0.11% | 0.15% | 0.13% |
| Mighty River Power (incl. SCGL) | 0.00% | 0.14% | 0.60% | 0.08% |
| Nelson Electricity | 0.17% | 0.16% | 0.00% | 0.13% |
| Network Tasman | 1.70% | 1.51% | 1.81% | 1.67% |
| Network Waitaki | 0.53% | 0.75% | 0.76% | 0.69% |
| New Zealand Steel | 0.27% | 1.54% | 1.36% | 1.99% |
| Nga Awa Purua Joint Venture | 0.00% | 0.06% | 0.00% | 0.00% |
| Norske Skog Tasman | 0.00% | 1.22% | 1.36% | 1.19% |
| Northpower | 2.50% | 2.73% | 1.51% | 2.76% |
| Nova Energy | 0.00% | 0.02% | 0.00% | 0.00% |
| NZ Aluminium Smelter | 9.92% | 7.31% | 6.65% | 13.14% |
| Origin Energy Resources | 0.14% | 0.11% | 0.00% | 0.18% |

| | | | | |
|---|---|---|---|---|
| Orion New Zealand | 9.93% | 10.54% | 8.31% | 8.59% |
| OtagoNet | 0.76% | 0.77% | 0.91% | 0.90% |
| Pan Pac Forest Products | 0.37% | 1.00% | 0.91% | 1.40% |
| Port Taranaki New Plymouth | 0.00% | 0.00% | 0.00% | 0.00% |
| Powerco (includes CHH) | 12.54% | 11.92% | 12.23% | 12.12% |
| PowerNet (inc Elec Inv & the power co.) | 2.53% | 2.43% | 2.42% | 2.19% |
| Scanpower | 0.24% | 0.18% | 0.15% | 0.23% |
| Solid Energy New Zealand | 0.00% | 0.00% | 0.00% | 0.00% |
| Southpark Utilities | 0.00% | 0.00% | 0.00% | 0.00% |
| Tararua Wind Power | 0.00% | 0.01% | 0.00% | 0.00% |
| The Lines Company | 0.61% | 0.78% | 0.91% | 0.65% |
| Top Energy | 0.67% | 0.66% | 0.76% | 0.47% |
| TrustPower | 0.00% | 0.00% | 0.15% | 0.00% |
| Unison Networks | 4.02% | 3.51% | 3.93% | 3.72% |
| Vector | 26.97% | 24.14% | 24.92% | 22.96% |
| Waipa Networks | 1.06% | 0.88% | 0.91% | 1.06% |
| WEL Networks | 3.36% | 3.46% | 3.32% | 2.44% |
| Wellington Electricity Lines | 8.33% | 6.88% | 6.65% | 6.01% |
| Westpower | 0.25% | 0.55% | 0.91% | 0.48% |
| Winstone Pulp International | 0.40% | 0.45% | 0.45% | 0.68% |
| Other | 0.00% | 0.00% | 0.91% | 0.00% |
| **Total** | **100.00%** | **100.00%** | **100.00%** | **100.00%** |

## APPENDIX I: DEPRECIATED HISTORIC COST V. REPLACEMENT COST CHARGING

In this appendix we outline the key differences between use of depreciated historic cost (DHC) and replacement cost (RC) for pricing purposes.  For the avoidance of doubt, when we refer to RC we mean the same methodology currently used by the TPM for connection charges (though we note the Authority also describes this as “average historic cost”).

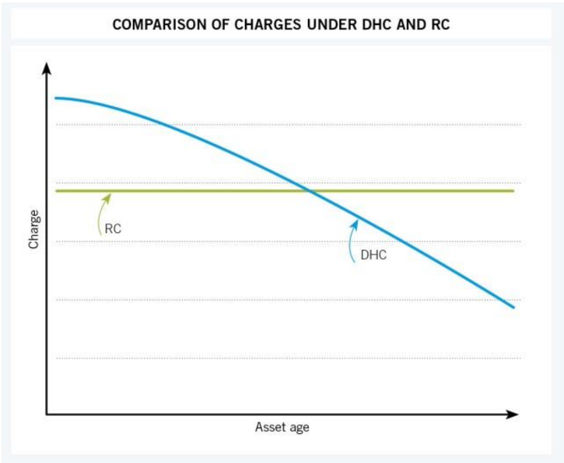
The choice between RC and DHC changes the depreciation profile of how costs are allocated.

A DHC methodology ‘front loads’ the depreciation, with asset valuation (and price) declining over time through the life of an asset.

An RC approach ‘flat lines’ the depreciation so that asset valuation (and price) is constant through time. This latter approach is recognised under the Second Issues Paper position as “RC charging is … consistent with what occurs in workably competitive markets for utility services. For these types of services, aesthetics are largely irrelevant to the benefits customers receive from the service, and therefore charges do not reflect the age of the asset providing the service”.[61]

The two approaches are shown in Figure 9.

Figure 9 DHC and RC charge profiles

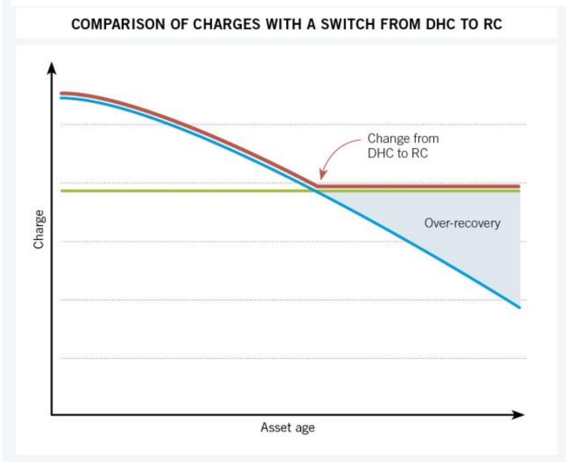



### Impact of changing the valuation of allocated assets

The current interconnection charge is based on the aggregate DHC of ALL interconnection assets.  A decision to change from the current postage stamp (interconnection) charge to AoB charging (described as a change from DHC to RC) could be thought to be potential double recovery as identified by the Authority[62].

We agree that there is a chance that a change from DHC to RC, <u>all other things being equal</u>, **could** disadvantage customers supplied by older assets. They could have paid a higher amount upfront, reflecting the depreciation on the asset, then when they should benefit from lower prices due to the lower DHC value, they could incur a higher RC based charge.  This is depicted in Figure 10. The red trace shows the change from DHC to RC and the shaded area represents the ‘double recovery’ or over-charging’.[63]

Figure 10: Switch from DHC to RC charging




[61] Electricity Authority, Second Issues Paper, Transmission Pricing Methodology: Issues and proposal, 17 May 2015, paragraph 7.143.
[62] Page 113 Para.7.160 (c)  2nd Issues paper

[63] It is worth noting the revenue cap Transpower operates under precludes it from double recovering the cost of its assets. That doesn’t mean an individual customer couldn’t potentially pay twice, and subsidise other customers.

However, the ‘all other things being equal’ qualification is a key assumption that does not hold i.e. all other things aren’t held constant.

Under the proposed AoB charging regime, there are two main changes occurring at the same time; a change in how assets are valued **and** how the assets are allocated:

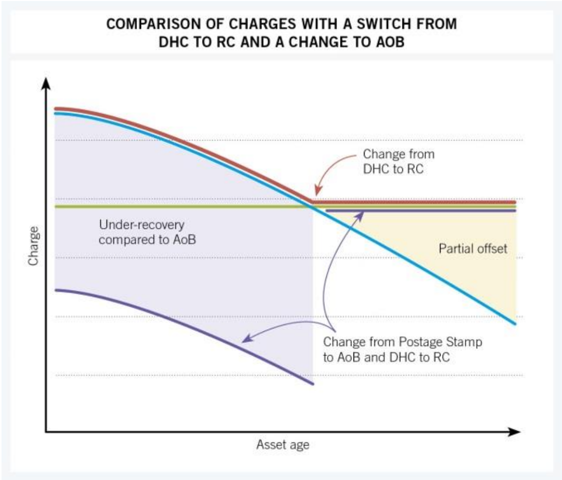
- Eligible investments are allocated to generators and load on the basis of AoB rather than allocated across load under a postage stamp (interconnection) or allocated to South Island generators on the basis of historic MWh injections (HVDC)
- Sunk assets are proposed to be valued at DHC and new assets at RC.

Figure 11 shows that a move from postage stamp to AoB charging shouldn’t result in customers paying for assets twice. A customer (e.g. Auckland and Northland) may end up paying more going forward due to use of RC but they won’t necessarily end up paying twice for the simple reason that under postage stamp the costs of the interconnection assets were allocated amongst all customers.

A customer that would incur an AOB charge was only paying part of the cost of the asset under the previous postage stamp (or potentially nothing in the case of generators).

This makes it less likely they could end up paying for the asset ‘twice’.

**Figure 11**




The new AOB charge would have to cause an ‘over-shoot’ that more than offset the historic ‘underpayment’ (of postage stamp relative to AoB) for the ‘paying for assets twice’ scenario to eventuate. In other words, the yellow shaded area (additional payment under a switch to RC) would need to exceed the crimson shaded area (payment ‘shortfall’ under postage stamp relative to AOB) in Figure 11.

The risk of ‘paying for an asset twice’ is further reduced when the assets are relatively new i.e. charges under RC are less than DHC. Preliminary estimates of RC by Transpower indicate RC charges are less than DHC for most eligible investments, reflecting they were all approved by the Electricity Commission and Commerce Commission between July 2007 and May 2014. This would mean the “indicative charges” for eligible investments, under AOB, would be lower than those contained in the Second Issues Paper if RC was applied rather than DHC. The residual charges would be proportionately higher