

ATTACHMENT B: BACKGROUND AND SUPPORTING INFORMATION

13 February 2015

Keeping the energy flowing



TRANSPower



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1. INTRODUCTION

Transpower has undertaken a review of the electricity transmission pricing methodology (TPM) in accordance with clause 12.85 of Part 12 of the Electricity Industry Participation Code 2010 (the Code). Details of the Transpower TPM Operational Review are available at:

<https://www.transpower.co.nz/about-us/industry-information/tpm-development>

The purpose of the TPM Operational Review is to determine whether there are problems with the TPM that could be addressed within the constraints of the existing “Guidelines for Transpower: Transmission Pricing Methodology” (the TPM Guidelines), 24 March 2006.¹

We appreciate the support and assistance we have received from the Authority, our customers, and other interested parties. This has provided valuable grounding for and stress testing of our thinking. Our analysis has been adapted in light of stakeholder input and in several instances this has flowed through into amended proposals. For example, we departed from our tentative proposal for a diluted HAMI charge and changed to a MWh HVDC charge proposal, and we have not proceeded with proposals to de-rate USI HVDC charges or amalgamate RCPD pricing regions.

We have now advanced the TPM Operational Review to the stage of making proposals to the Authority to amend the TPM. We believe the proposed amendments are low cost, incremental and readily reversible. This means there is a very low risk to consumers that they would be harmful, and the proposals can be safely accepted regardless of the potential outcome of the Authority’s TPM review.²

The Authority will now determine whether or not each of our Code Amendment Proposals (CAPs) will be approved. We stress, given concerns from some submitters that Transpower should not be making decisions on non-technical transmission pricing issues, that the Authority is the ultimate decision-maker on changes to the TPM, regardless of whether it is part of our clause 12.85 review or the Authority’s own clause 12.86 review.

Our objective is to have any TPM variations made by 1 September 2015 (the start of the Capacity Measurement Period (CMP)). This is based on an assumption the Authority will be able to complete its review by 1 June 2015. The individual CAPs identify the implications of any delays in the Authority’s process for timing of implementation.

1.1. PURPOSE OF THIS PAPER

The principal purposes of the paper are to provide:

- background material on the consultative and analytical process we have followed
- supporting information on the five TPM CAPs (it does not replicate all the information provided in the CAP templates)
- respond to points raised in submissions to our second consultation.³

¹ The TPM Guidelines have also been placed on Transpower’s website at: <https://www.transpower.co.nz/about-us/industry-information/tpm-development>

² The Authority’s TPM review could result in some of the changes being temporary, or confirmed as permanent changes as part of an “enhanced” status quo or, otherwise, revised TPM.

³ The predominant focus of the paper is on the submissions from the second consultation paper. Our assessment of responses to the initial consultation paper is contained in the second consultation paper.

The paper also identifies issues we consider the Authority should review as part of its TPM Operational Review, and provides guidance in relation to our intentions for future periodic TPM Operational Reviews.

1.2. NATURE OF THE CODE AMENDMENT PROPOSALS

We consider that our February 2015 TPM CAPs:

- better promote efficiency and the long-term interests of consumers – they bring forward improvements to the TPM and lock in efficiency gains sooner than could be achieved by waiting for the conclusion of the Authority’s TPM review (due to the timing of that review)
- are straight-forward and low cost to implement (we have not identified any costs that could potentially negate the benefits of the changes) and are proportionate to the problems we have identified and consistent with the TPM Guidelines
- are incremental and ‘no regrets’ changes that do not preclude further changes to TPM design if better options are subsequently identified
- could be adopted in advance of the potential outcome of the Authority’s TPM review, and regardless of whether they end-up being temporary or permanent changes and create an “enhanced” status quo, against which the Authority can evaluate potential options as part of the its TPM review
- have been developed through a consultative process and have a broad level of industry support (though not necessarily consensus).

1.3. CODE AMENDMENT REQUIREMENTS

Clause 12.87 of the Code requires that “A review of the transmission pricing methodology must take into account the requirements of clauses 12.79 and 12.89(1).”

We have assessed the TPM, and the CAPs, against the statutory objective in section 15 of the Electricity Industry Act 2010 (clause 12.79). We have developed our CAPs to be consistent with:

- any determination under Part 4 of the Commerce Act (clause 12.89(1)(a));
- the Authority’s objective in section 15 of the Act (clause 12.89(1)(b)); and
- the TPM Guidelines (clause 12.89(1)(c)).

We have also produced indicative prices (clause 12.89(2)) to allow the Authority and interested parties to understand the impact of the methodology on designated transmission customers.

2. THE CONSULTATIVE PROCESS

Clause 12.85 of the Code provides that “At any time, Transpower may submit to the Authority a proposed variation of its transmission pricing methodology, provided that the submission is made at least 12 months after the last Authority approval of the transmission pricing methodology.”

This is the first time we have reviewed the TPM and the first time we have proposed a variation. The table below details the TPM Operational Review process we have undertaken.

Table 1 Key dates and actions until February 2015

Task	Date
<ul style="list-style-type: none"> Test with the Authority and a subset of our customers and interested parties whether they considered that Transpower should undertake a TPM Operational Review at this stage. 	Early May 2014
<ul style="list-style-type: none"> Formally initiate the review of the TPM, by announcing details of the review on our website: https://www.transpower.co.nz/about-us/industry-information/tpm-development 	21 May 2014
<ul style="list-style-type: none"> initial consultation paper published 	9 July 2014
<ul style="list-style-type: none"> Bi-lateral discussions with stakeholders. 	July-August 2014
<ul style="list-style-type: none"> Update Paper published 	24 September 2014
<ul style="list-style-type: none"> Further analysis published 	Various
<ul style="list-style-type: none"> second consultation paper published 	13 November 2014
<ul style="list-style-type: none"> Bi-lateral discussions with stakeholders 	November-December 2014
<ul style="list-style-type: none"> Stakeholder briefing/workshops in Auckland, Christchurch and Wellington 	2-10 December 2014
<ul style="list-style-type: none"> Transpower reviews responses and revisits analysis 	To February 2015
<ul style="list-style-type: none"> Transpower submits its Code amendment proposals to the Authority 	13 February 2015
<ul style="list-style-type: none"> Authority Code amendment review process starts 	mid-February 2015
<ul style="list-style-type: none"> Authority decision (indicative timing) 	June 2015
<ul style="list-style-type: none"> Transpower implements any changes to the TPM, informs customers 	June – September 2015
<ul style="list-style-type: none"> Changes take effect for CMP 2015/16 	1 September 2015

2.1. CONCERNS ABOUT TIMING AND OVERLAP WITH AUTHORITY'S REVIEW

Some parties have expressed concern with the time-frame for the Authority to complete its review of our CAPs:

Some of the TPM issues raised and amendments suggested in the document are controversial and are likely to take extended time to consider.⁴

Transpower's proposed timetable allows three months for the Authority to consult on Transpower's proposed changes to the TPM. In Meridian's view, this timeframe may be too short to properly consider and consult on these changes ... If Transpower's review continues with its current scope, Meridian would expect the Authority to conduct a full assessment of the proposed changes, including an assessment of alternative options and involving a full submission process. In our experience, such a process may take 6-12 months.⁵

... we do have concerns regarding the level of analysis that is possible under such tight timeframes to support any changes (largely to do with any change in structure of the HVDC link charges).⁶

We acknowledge that our objective of implementing TPM changes in advance of the CMP commencing 1 September 2015 constrains the time available for this review. However, we consider the proposals are straight forward and have been thoroughly consulted on. Further, we understand from the Authority that it considers there to be sufficient time for it to review, consult on and reach a decision on our proposals.

2.2. WHY WE UNDERTOOK A CLAUSE 12.85 REVIEW NOW

We think there is value in periodically reviewing the TPM to identify any problems and to ensure the TPM remains fit for purpose as circumstances change and to reflect new insights into the intended and unintended effects of transmission pricing signals.

The following specific factors have also prompted our review:

- **Review is consistent with the objectives in our SCI:** our Statement of Corporate Intent requires Transpower to "seek to efficiently recover the full costs of its services".
- **Some TPM pricing signals are now too strong:** our recently completed grid upgrade programme has reduced congestion and, at the same time, increased the strength of transmission price signals.
- **Ongoing TPM reviews have identified issues we could address:** various TPM Guideline reviews have identified potential issues with the TPM we may be able to address directly without having to amend the TPM Guidelines. This was a clear message from submissions on the Authority's Problem Definition Working Paper (PDWP).⁷
- **We have been requested to undertake a review:** we have had various requests to review aspects of the TPM and many of our customers and stakeholders support the review.
- **Immediate efficiency improvements are available:** there is an opportunity to achieve efficiency gains at least two years ahead of any changes resulting from the Authority's review. As Contact Energy observed, "efficiency gains can be made within the existing Code framework, without affecting the work of the Electricity Authority ..."⁸

⁴ NZ Steel, Initial consultation on possible TPM operational changes, response to Question 3.

⁵ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, pages 3 and 4.

⁶ Trustpower, TRUSTPOWER SUBMISSION: TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, paragraph response to Question 2, paragraph 2.2.

⁷ Electricity Authority, Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets, 16 September 2014.

⁸ Contact Energy, Re: Transpower TPM Operational Review: Initial Consultation Paper, 8 August 2014, page 1.

For the avoidance of doubt, we would not have continued with the Operational Review beyond the initial stages without the clear support of our customers and other interested parties that submitted on the Initial Consultation Paper. We also tested the desirability of conducting this Operational Review with the Authority.

2.3. CO-ORDINATION WITH THE AUTHORITY'S TPM REVIEW

The potential for overlap between this work and the Authority's TPM review was recognised from the outset and stakeholders encouraged Transpower to coordinate with the Authority. We have done this and appreciate the constructive approach of the Authority and in particular its TPM project team. We consider the Authority has done well to help ensure coherency between the two reviews and provide clear communications to stakeholders⁹.

⁹ Including allowing Transpower to utilise its widely received Market Brief to notify stakeholders of our two consultations.

3. ANALYTICAL APPROACH

In this section we address the policy objectives for the TPM and the analytical approach we have adopted for our review.

3.1. GUIDED BY THE CODE AND SECTION 15 OBJECTIVE

Each of the CAPs that we have recommended to the Authority improves efficiency, or corrects errors or anomalies in the TPM (which also improves efficiency).

We have been guided by the Code and the Authority's section 15 statutory objective; specifically:

Clause 12.78 of the Code: The purpose of the **transmission pricing methodology** 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** objective in section 15 of the **Act**.

Clause 12.79 of the Code: **Transpower**, in developing the **transmission pricing methodology**, and the **Authority**, in approving the **transmission pricing methodology**, must assess the **transmission pricing methodology** against the **Authority's** statutory objective in section 15 of the **Act**.

Section 15 of the Electricity Industry Act 2010: the objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry, for the long-term benefit of consumers.

When we assessed the impact of the potential changes to the TPM, we explicitly considered both the efficiency and pricing impacts of the change although our recommendations are based on efficiency impacts.

3.2. ANALYTICAL APPROACH

We have undertaken this analysis with the Authority's statutory objective and obligations in mind, and with the aim of allowing stakeholders to easily understand and test our analysis. Our analytical approach has been:

- Step 1. revisit background:** for each charge type we review the reasons for the current TPM design choices
- Step 2. situation assessment:** so we can overlay environmental considerations (such as current use of and the current state of the grid, forecast future demand and investment expectations) into the problem definition and subsequent stages
- Step 3. problem definition:** revisit the problem definition from our July consultation in light of submissions, the Authority's PDWP and further analysis we have undertaken (including steps 1 and 2 above)
- Step 4. re-define options:** in light of submissions, the Authority's PDWP and our further analysis (and steps 1-3 above) for each problem

Step 5. assess options: against the statutory objective in section 15 of the Electricity Industry Act, and our assessment criteria, using a combination of qualitative and quantitative methods.

3.3. ASSESSMENT CRITERIA

We used the following assessment criteria to assist our review:¹⁰

1. Is the option consistent with the TPM Guidelines?
2. Does the option address an identified problem with the TPM, and is it proportionate to the size and nature of the problem?
3. Would the option better promote the long-term interests of consumers of electricity by:
 - promoting competition, reliable supply and efficient operation of the electricity industry
 - better reflecting customer preferences
 - correcting errors or anomalies in the TPM?
4. Is the option practical (taking into account the costs of change, and the desirability of consistency and stability over time)?

Criterion 2 above is new, reflecting feedback to the second consultation paper (this was implicit in our earlier analysis) and the desirability of options being proportionate to identified problems e.g. Mighty River Power¹¹ and Genesis Energy¹². Similarly, the ENA observes that “Clearly identifying and defining the problem is a crucial step in the regulatory process as the problem definition establishes the prima facie case for regulatory intervention and the reason for discussing options for change”.¹³

Criteria 1 and 4 reflect practical constraints we face in meeting the statutory objective in section 15 of the Electricity Industry Act. We note though that while the TPM Guidelines (criterion 1) has limited the potential options available to us, they have not prevented us from developing options that would address the problems we have identified.

Criterion 3 is an explicit reiteration of the statutory objective, as specified in section 15 of the Electricity Industry Act. As noted by Orion: “In terms of the four-subparts ... the first is effectively the way the Authority clarifies its statutory objective, so it should get considerable weight ...”¹⁴

The remaining sub-bullets of Bullet 4 are implicit subcomponents of the section 15 statutory objective. “Better reflecting customer preferences” mirrors achieving outcomes consistent with workably competitive markets while “correcting errors and anomalies” is an implicit component of efficient operation of the electricity industry.

The assessment criteria were supported by Contact Energy, Mighty River Power, Pacific Aluminium, Orion, Trustpower, and Unison. Meridian was the only party not to support the criteria.

¹⁰ Refer to Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 3 for a more a detailed discussion on assessment criteria.

¹¹ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, page 1.

¹² Genesis Energy, Support for proportional changes to fix problems with current transmission cost allocation, 22 December 2014, page 1.

¹³ ENA, Submission on Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets, 28 October 2014, paragraph 1.

¹⁴ Orion, Submission on 2014/15 TPM Operational Review: second consultation paper, 19 December 2014, paragraph 13.

4. SITUATION ASSESSMENT

In this section we assess changes that have occurred since the TPM was introduced in 2008 that may impact on the optimal settings of the TPM, and give rise to a need for amendments. The section largely reflects section 4 from our second consultation paper (there is no material new evidence or substantive change to the situation assessment).

4.1. WE HAVE COMPLETED A MAJOR INVESTMENT PROGRAMME

Grid upgrades have relieved capacity constraints into the Upper North Island (UNI) region

Since the TPM was introduced, the major investments that were being planned to relieve constraints into and within the UNI region have been completed. These include:

- the North Island Grid Upgrade (NIGU)
- the North Auckland and Northland (NAaN) project
- the Wairaki ring project
- UNI dynamic reactive support.

As a result of these projects, and flattening demand growth, there are only relatively small, localised demand-driven investments expected in the region within the foreseeable future. We may invest in series capacitors in the UNI region, but this is most likely to be justified as an economic investment to reduce transmission losses, rather than for reliability reasons.

The view that there is likely to be limited demand-driven investment to support UNI demand growth is supported by the majority of submitters who commented on the matter.¹⁵ For example, Pacific Aluminium noted:

...investment in grid upgrades in the UNI means that there is no longer a reason for sending a signal to control load in peak demand periods for the purpose of deferring further investment.¹⁶

Similarly, Powerco noted:

...now that the North Auckland and Northland (NAaN) and North Island Grid Upgrade (NIGU) investments have been completed and commissioned, there is no need to continue to base the Upper North Island (UNI) interconnection charge on N =12, and that to continue to do so would, in fact, be costly from a national perspective, because retaining N =12 would cause some load to continue to be controlled even though transmission capacity in the region is now ample.¹⁷

There were, however, some differing views and qualifications. Contact Energy, for example, pointed out that NZAS smelter shutting down could cause a significant shift in transmission grid usage:¹⁸

In our view this is quite a narrow unconnected view of the UNI situation. If Tiwai shuts down then the demand for thermal, much of which is located in the UNI may be uneconomic to maintain. The value of peak demand will immediately resurface so while we agree in a steady state world, Transpower should be prepared to be dynamic on this issue and recognise the feedback of how demand in the LSI affects peak issues in the UNI.

¹⁵ Genesis Energy, Mighty River Power (qualified), Pacific Aluminium, Northpower, Powerco, Trustpower (“in the short- to medium term”) Unison, and Vector.

¹⁶ Pacific Aluminium, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, paragraph 10.

¹⁷ Powerco, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, response to Question 4.

¹⁸ Contact Energy, Transpower TPM operational review: Initial Consultation, 8 August 2014, response to Question 4.

Mighty River Power commented:¹⁹

Given current levels of installed transmission capacity into the UNI, UNI demand and UNI thermal generation one possible conclusion is peaks could send an unnecessarily strong signal to reduce demand around expected peak periods. However, MRP's analysis suggests that this picture could well change (in say the next 5 years) if demand in Auckland were to grow and one or more major thermal units in the UNI were decommissioned, both of which are relatively credible scenarios. This could give rise to a combination of thermal security and voltage stability constraints restricting import into the UNI around peak demand periods.

Overall, we agree that the short to medium term outlook for demand-driven investment in the UNI is benign compared to when the TPM was set but recognise points made by Contact and Mighty River Power that there are scenarios where further demand-driven investment would be required.

There is limited deferral value available in the Upper South Island (USI) region

The USI region is primarily supplied from hydro capacity in the lower South Island. There are currently three lines from the south, which run to our substation at Islington. A new line will be required at some stage but, before that, a lower cost series of investments are being used to unlock the thermal capacity in the existing lines. In 2010 we installed a SVC at Islington, in 2014 we installed a new bus coupler, and between 2022 and 2028 we expect to build a switching station at Orari in South Canterbury. The new line will be required after that, but we do not expect this to be needed until sometime after 2040.

The Orari project may cost in the order of \$65m, while the cost of a new line could be of a similar magnitude to the NIGU project (which cost \$895m when completed in 2013). The value of deferring these projects for one year in the mid 2020s and 2040 is estimated at approximately \$4m and \$58m per annum respectively (calculated as *capital cost times Transpower's cost of debt*). It should be noted that:

- the cost and timing assumptions are indicative only
- in both cases the transmission upgrade would also deliver benefits such as increased reliability, reduced losses and less price volatility (which are not discounted from the deferral benefit estimates above).

While the benefit of deferring these potential investments in the mid 2020s and 2040s could be significant there is limited value, having just installed the new bus coupler at Islington, in providing a strong peak price signal in the USI at this point (or for several years).

Other USI context

On 1 December 2014 we transferred ownership of 66kV assets west of Stoke to Network Tasman. This follows transfer of Kaikoura substation and its associated line to Mainpower in 2012. Both transfers reduced the footprint and value of Transpower's USI transmission grid. The Network Tasman transfer will also result in Trustpower's Cobb hydro station becoming embedded behind the Stoke grid exit point, and hence avoiding HVDC charges. Our investment programme is dominated by asset condition-driven projects.

Transpower's RCP2 investment programme

The Commerce Commission recently approved our capital expenditure programme for the five year RCP2 period from 2015/16 to 2019/20.²⁰ Compared to the preceding five years, the programme is smaller overall and is dominated by replacement and refurbishment (R&R) rather than enhancement and development (E&D). The total value of the approved E&D capex (including interest during

¹⁹ Mighty River Power, Transpower TPM Operational Review: Initial Consultation, 6 August 2014, response to Question 4.

²⁰ Commerce Commission "Setting Transpower's individual price quality path 2015 -2020 final reasons and decision paper", 29 August 2014, table 5.1

construction and in real 2012/13 prices) is \$116.3m. The approved grid R&R capex (on the same basis) is \$782.9m.

The HVDC link has been upgraded

When the current TPM was established in 2006, Transpower had proposed investment in an upgrade to the inter-island High Voltage Direct Current (HVDC) link. In 2007, Transpower removed the original Pole 1 from full service and in 2008 the Electricity Commission approved Transpower's proposed upgrade. Works started in 2010 and were recently completed. Pole 1 has now been fully removed from service, the new Pole 3 is in service and the Pole 2 control systems have been upgraded.

The upgrades have increased the capacity of the link and enabled new functionality. The value of the link has increased, along with the annual revenue requirement and the HVDC pricing rate. The revenue requirement and pricing rate have now plateaued and, with limited R&R capex required over the next five years, are expected to ease.

4.2. DEMAND GROWTH HAS BEEN FLATTER THAN FORECAST AND THE OUTLOOK IS UNCERTAIN

Apart from a new national peak in 2011 (due to an unusual polar weather event) demand growth (in peak and GWh terms) has been flatter than previously forecast. Demand growth in recent years has been affected by a range of factors including:

- global recession, causing reduced industrial demand e.g. Tiwai Aluminium Smelter and Norske Skog Tasman mill
- the Christchurch earthquakes
- increased uptake of energy efficiency lighting and appliances²¹
- increases in generation embedded within distribution networks (which reduces demand observed at grid exit points).

Consultation on the EDB DPP 2015-2020 reset also highlights "a significant change in market conditions facing the energy supply industry occurred around 2007 with significantly reduced growth rate in demand" in New Zealand that has also been "observed in Australia, Canada and the US".²²

Consistent with this observation, Carter Holt Harvey has noted that a trend appears "...to becoming apparent with consumer behaviour (e.g. load reduction due to more efficient appliances and equipment, and potentially disruptive technologies such as PV, electric vehicles and enhanced methods for consumers to manage their electricity use) that future investment in augmenting transmission services may well be quite minimal or even non-existent".²³

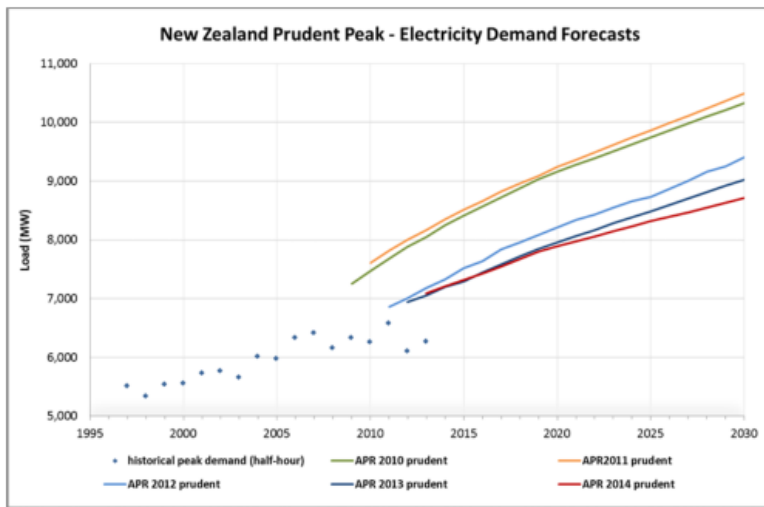
The future electricity demand outlook remains highly uncertain and prudent peak forecasts (PPF) for grid delivered electricity have moved progressively lower over the last five years in response to ongoing flat demand growth. Figure 1 shows the ongoing revision to PPF over the last five years.

²¹ Refer, for example, to Vector, Submission on DPP low-cost forecasting approaches, 15 August 2015, paragraphs 42-45.

²² Refer, for example, to Economic Insights, Electricity Distribution Industry Productivity Analysis: 1996-2013, 24 June 2014, pages iii and iv

²³ CarterHoltHarvey, Transmission pricing methodology: Problem definition working paper, 28 October 2014, response to question 2.

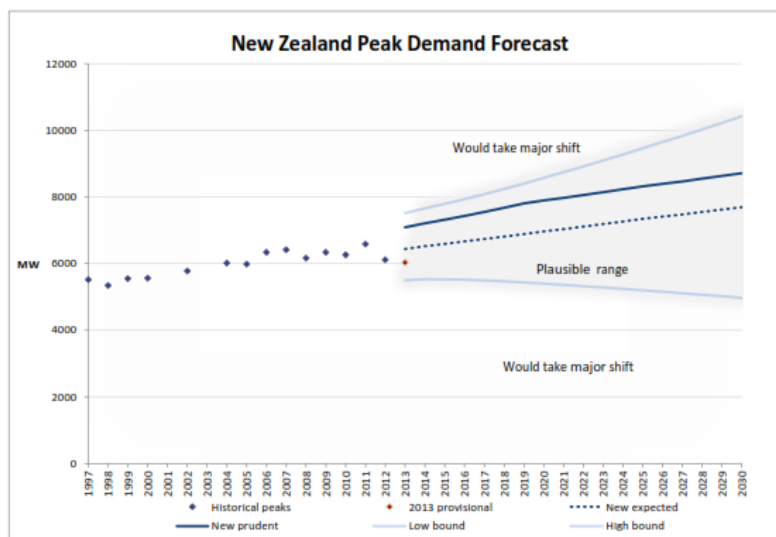
Figure 1 Iteration of Transpower's prudent peak demand forecast



Source: Transpower APR, 2014, chapter 4

We are in the process of updating the PPF and further downward adjustment is possible. The extent of uncertainty is shown by Figure 2, which presents the range of plausible peak demand tracks. Disruptive technologies such as solar photovoltaics, battery storage, electric vehicles and developments in demand response only add to the uncertainties regarding future levels of demand growth.

Figure 2 range of peak demand forecasts



Source: Summary of Transpower's peak forecast process, June 2013

4.3. TRANSMISSION PRICE SIGNALS ARE MUCH STRONGER NOW THAN WHEN THEY WERE SET

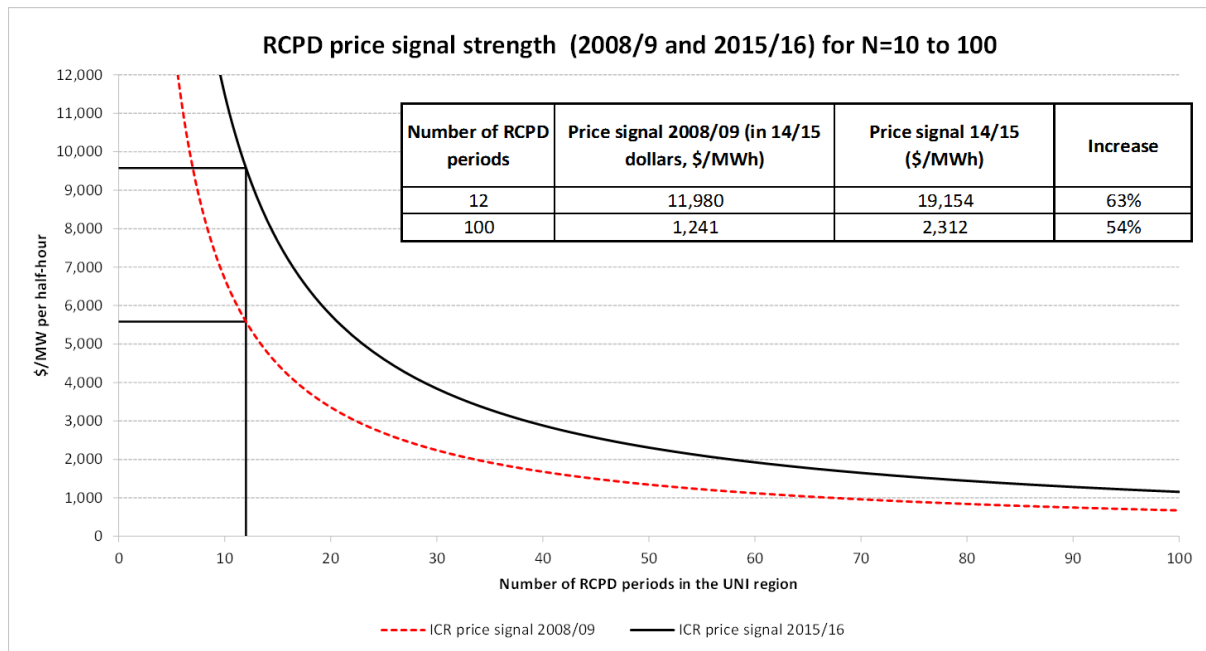
In constant dollar terms, total transmission revenue has returned to the same level as the early 1990s when Transpower was established and we expect transmission revenue to be flat or falling in real terms over the next five years. However, total transmission revenue is significantly higher than when the current TPM was established and, consequently, the RCPD and HVDC pricing signals are much stronger than when they were set.

4.3.1. RCPD PRICE SIGNALS

A combination of capacity expansion investments and flat demand growth has led to an increase in the interconnection rate (ICR) of more than 60% from \$68 per kW in 2008/09 to \$114 per kW in 2014/15 (both in 2014/15 dollars). Without any adjustment to tariff design, this means the strength of the transmission price signal has increased by 60% nationwide since the current TPM was established.

Figure 3 compares the strength of the price signal in the UNI in 2008/09 and the strength of the forecast price signal 2015/16. In each case, the price signal is shown as a function of the number of peaks used to set charges. This is referred to as the 'N' setting. The price signal is the transmission charge avoided by sustaining a 1 MW reduction in consumption over a half hour price-setting period.

Figure 3 Interconnection Rate Variation Analysis (for 08/09 and 15/16 by 'N')



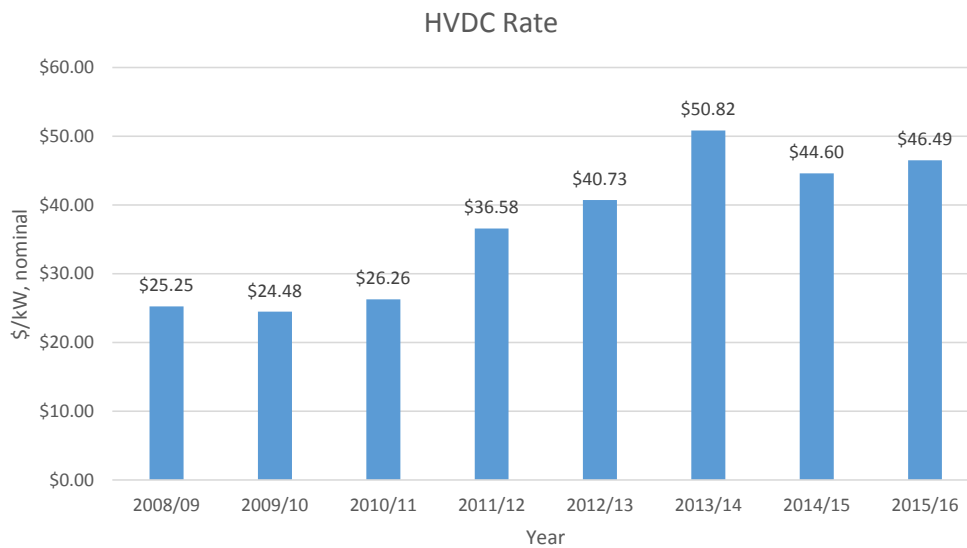
We recognise comments made by Orion²⁴ in relation to the sharpness of the price signal and agree that the effective price signal will be affected by a number of factors including the ability to predict when peaks will occur.

4.3.2. HVDC PRICE SIGNAL

A combination of the costs associated with the HVDC upgrade, and a reduction in the level of South Island generation attracting the HAMI charge has resulted in an increase of approximately 60% in the HVDC rate from \$27 per kW in 2008 to \$44.60 per kW (in 2014/15 dollars). The effect of that change is an equivalent increase in the price signal provided by HAMI from when the TPM was introduced. Figure 4 illustrates the change in the HVDC rates since 2008.

²⁴ Orion, Transpower TPM Operational Review: second Consultation, 19 December 2014, paragraphs 8-11.

Figure 4 HVDC rate changes



We expect HVDC revenue to be flat or falling in real (and nominal) terms over the next five years.

4.4. THE COMPETITIVE AND REGULATORY ENVIRONMENT HAS PROGRESSED

In addition to the factors outlined above, the New Zealand electricity sector’s competitive and regulatory environment has changed significantly since 2008. The implications of these changes are relevant considerations for our TPM review process.

- The regulatory framework applicable to Transpower (and EDBs) has evolved and matured. It provides Transpower with strong incentives to optimise expenditure to achieve the lowest whole of life costs for the regulated service we provide. We have a strong incentive to scrutinise, test and challenge assumptions made by customers (EDBs, generators, direct connects) or any other party involved in the investment planning process.
- The combination of equity listings, intensifying competition and political pressure to contain retail price increases has and continues to increase the scrutiny that retailers place on lines company costs at all levels – whether investment, operating or cost of capital.
- In a recent presentation to the Business NZ Energy Council the Commerce Commission aptly described a number of ‘emerging challenges’ faced by electricity lines companies including Transpower; they include:
 - future demand [uncertainty]
 - [emergence of] disruptive technology
 - [concerns regarding] affordability and fuel poverty
 - [the possibility of a] death spiral [dynamic if fixed costs need to be recovered from a shrinking customer base]
 - changing consumer expectations
 - new business models
 - climate change (extreme weather).

The emerging challenges identified by the Commerce Commission combine to create greater uncertainty and risk for investors that seems likely to result in a more cautious approach to investment across the network sector.

4.5. DEMAND RESPONSE HAS BECOME A VIABLE TOOL FOR DEFERRING TRANSMISSION INVESTMENT

Procured demand response (DR) can complement or, in some circumstance, substitute for price signals in efficiently deferring transmission investment. The role that DR can play will depend on a number of factors; for example, as Orion observes²⁵, if extensive load management is already occurring (for distribution network management or other reasons) then available DR options may not be cost effective.

Although the potential of DR has long been recognised it was unproven and initial trials were not as successful as hoped. However, the implementation of an off-the-shelf web-based system, the Demand Response Management System (DRMS), in 2011 helped lower the barrier to participation. Using this new system, Transpower has run successful demand response programmes.

Findings of the 2013 DR programme

The *2013 Demand Response Programme Report*²⁶ sets out the findings of Transpower’s first commercial demand response programme; in summary:

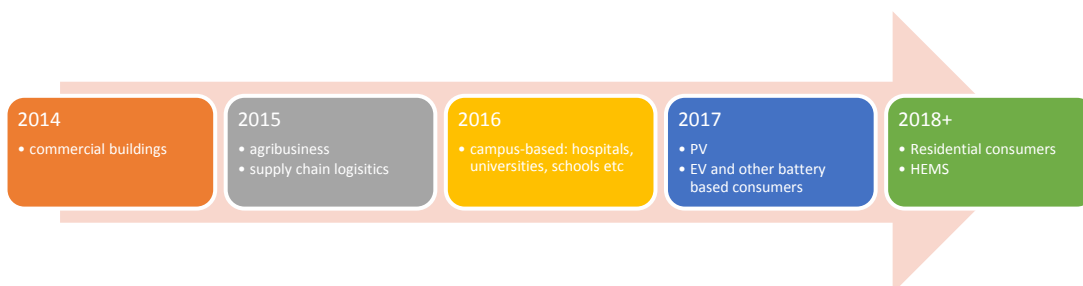
- 8 participants with 134MW of registered
- 20 demand response events were successfully called, the largest event was 175MW over 2 hours (during testing for the HVDC Pole 3 project)
- natural price points were found for different types of DR

Since the 2013 programme concluded we have been working with potential providers of DR to identify growth potential and are working with the Commerce Commission and the Authority to ensure that DR can play an effective role in deferring transmission investment.

Next steps for DR

In August 2014 the Commerce Commission approved further funding for Transpower to maintain and continue develop its DR capability during the five year regulatory control period commencing June 2014/15.

Our DR development programme continues over the next five years and builds on the previous work by enabling participation by different consumer segments. Particular focus will be given to identifying barriers for participation. An overview of the timeline is shown below.



²⁵ Orion, Transpower TPM Operational Review: second Consultation, 19 December 2014, paragraphs 7.

²⁶ See: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Demand%20Response%20Programme%20Report%20Summary.pdf

5. SETTING THE VALUE OF “N”

We propose the RCPD charges for UNI and USI be amended by resetting N from 12 to 100. If this proposal is rejected, we propose the RCPD charges for UNI only be amended by setting N from 12 to 100.

We do not consider that a phasing in period is warranted and propose that this change be implemented for the capacity measurement period beginning 1 September 2015.

5.1. TPM GUIDELINES 2006

The relevant interconnection tariff design guidelines are:

Table 2 Guidelines 12 and 13 for interconnection assets

Guideline 12	Charges for existing and new interconnection assets should be on a postage stamp basis. This is similar to current interconnection charges.
Guideline 13	Transpower should review the existing basis on which it calculates the interconnection charge at a grid exit point. Specifically, Transpower should review whether using the 12 highest half-hour offtake peaks in the 12 months up to and including the current month is the most consistent with pricing principle rule 227. This review includes consideration of anytime versus regional or national coincident peaks.

This review revisits whether using N=12 for the UNI and USI regions remains appropriate. This has not been reviewed since the current TPM was introduced.

5.2. BACKGROUND

When we designed the current TPM, we decided it was appropriate to establish four regions for the interconnection charge – UNI, USI, Lower North Island (LNI) and Lower South Island (LSI) – and to set charges based on RCPD. This design was intended to encourage users to avoid consumption during regional peaks in the UNI and USI regions, and to avoid sending a strong pricing signal in the LNI and LSI regions.

This design recognised:

- that growth in peak demand across the grid exit point (GXPs) in the UNI region was likely to drive significant transmission investment to supply that demand from the south
- like the UNI, the USI is an importing region in which growth in peak demand was likely to drive significant transmission investment²⁸

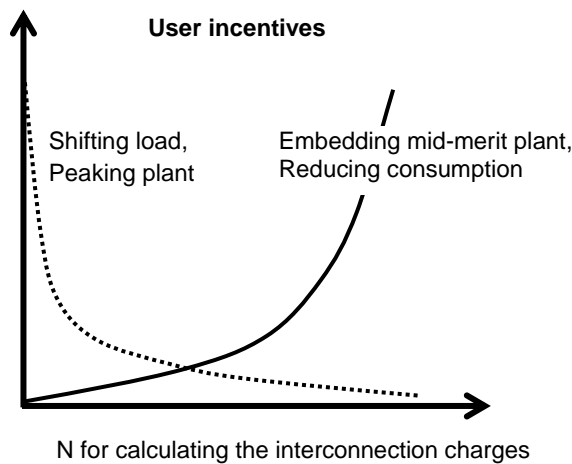
²⁷ Pricing Principle rule 2 was “the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options”

²⁸ Transpower, Transmission pricing methodology supplementary material, June 2006, page 45

- setting annual charges based on consumption during a small number of regional peak demand periods sends a strong signal to avoid using the grid during those periods i.e. a small 'N' sends a strong peak avoidance signal
- setting charges based on consumption during a larger number of periods sends a weaker signal to avoid peaks, but an increasing incentive to reduce net energy consumption i.e. a large 'N' sends an energy conservation signal
- nodal electricity prices already send a sophisticated locational signal, but economies of scale in transmission investment mean that nodal prices will tend to under-signal the cost of large transmission capacity expansions.

The following diagram, adapted from our 2006 paper explaining the TPM design, illustrates how the nature of the price signal changes with a different 'N' selection.

Figure 5 User incentive effect of different values of 'N'



Source: Transpower (adapted from Transmission pricing methodology supplementary materials, June 2006)

The value of N in each of the four regions was set to reflect the expected need for major investment in each region at the time the TPM was introduced:

Potentially there is a gain in efficiency if a small N is used to encourage reductions in peak demand where there are transmission constraints that are not adequately signalled by nodal prices. On the other hand, if there are no constraints there is a potential loss of efficiency if customers incur the costs of shifting demand when doing so will not affect the cost of future investment.²⁹

N was set at 12 for UNI and USI (reflecting the expected need for major new investment to meet demand growth) while an N of 100 was set for LNI and LSI (reflecting the relatively unconstrained grid and benign outlook for demand driven investment in those regions).

5.3. PROBLEM DEFINITION

In short, we consider that setting interconnection charges for the UNI and USI regions on the basis of demand during 12 regional peaks is sending a very strong pricing signal. We believe that N=12 is likely to be promoting high-cost peak avoidance – including unnecessarily costly investment in avoidance capability (e.g. peaking generation) and production changes (e.g. generation, production scheduling) that exceed any available transmission deferral benefits.

²⁹ Transpower, Transmission pricing methodology supplementary material, June 2006, page 42.

This view, at least with respect to the UNI region, was supported by the majority of submitters who commented on the matter.³⁰ The Authority's PDWP also raises questions over whether N should remain set at 12 for both UNI and USI.

5.3.1. THE STRENGTH OF THE PRICE SIGNAL

Figure 3 (in Section 4) shows that, when charges are set over 12 peak half hours (i.e. N=12), users in the UNI and USI regions can avoid \$9,500 by reducing consumption by 1 MW for half an hour. In variable cost terms, users can achieve a pay-off of \$19,000 per MWh. Following recent grid investment, this signal is more than 60% stronger than when the current TPM was established.

As Orion identifies³¹, users cannot predict the top 12 peak periods accurately in advance and are likely to achieve a 'success rate' of less than 100% i.e. their responses will sometimes be wasted (at least in terms of transmission charge avoidance). Further, the extent to which RCPD signals affect consumer behaviour is affected by a number of other factors; for example:

- The transmission pricing signal operates in conjunction with a range of other factors, such as wholesale electricity prices, distribution investment costs, etc (so it is difficult to isolate the effect of the transmission price on behaviour).
- For many small users, the price signal is not directly passed on in their distribution or retail tariffs (load is controlled for a variety of reasons including, perhaps predominantly for, distribution network investment reasons).
- EDBs are required to pay embedded generators on the basis of avoided transmission charges so, the price signal does not penetrate through to embedded generators.
- Large direct connect users receive the price signal directly and there is evidence of strong responses. Some large, non-grid connected users have pass-through contracts that mean they receive unaltered RCPD price signals (and expect they would respond in a similar way to grid connected users).

In practice, parties will weigh up a range of factors when deciding whether to respond to transmission pricing signals. However, the strength of the signal when N=12 is high relative to wholesale electricity prices and standby generation costs (and approaches estimates of the cost at which parties are willing to temporarily cease consumption altogether i.e. the value of lost load, or VoLL).

5.3.2. QUANTIFYING THE COST THAT N=12 MAY BE IMPOSING

The Authority (in their PDWP) and Castalia (in a submission on the PDWP for Genesis Energy) have both quantified the efficiency cost of having charges set over 12 peak periods.

The Authority's analysis is based on an estimated fully-variabilised cost for hot water load control of \$150 to \$1,000 per MWh. From this starting point, the Authority estimates costs with a net present value of up to \$96m. While this analysis may provide an indication of the relative scale of the problem, it is likely to overstate the cost because:

- there is typically a very low cost associated with calling hot water control once the infrastructure is in place, and provided hot water is not controlled too often in one day or for too long (i.e. so there is no impact on end user experience).
- transmission pricing is unlikely to be the main driver for EDBs investing in building, maintaining

³⁰ Genesis Energy, Mighty River Power (qualified), NZAS, Northpower, Powerco, Trustpower ("in the short- to medium term") Unison, and Vector.

³¹ Orion, Transpower TPM Operational Review: second Consultation, 19 December 2014, paragraphs 8-11.

and expanding hot water control capability. For example, Norske Skog comment “We suspect that distributors derive benefit from load shedding and controllable load due to avoiding investment in their own networks and revenue from interruptible load. The Authority appears to believe that this is not the case since it ascribes all of the costs to the TPM. In our view the Authority is in error.”³²

Castalia extended the Authority’s analysis by accounting for distribution benefits (the most direct financial reason for EDBs to control load is to manage distribution network capex) and avoided costs to direct-connect customers, and concluded the overall impact is between a benefit of \$4 million and a cost of \$18 million in present value terms (compared to the Authority’s calculation of between a benefit of \$11 million and a cost of \$96 million PV).

In our view, the greatest inefficiency is likely to be associated with:

- demand shifting in cases where this has non-trivial costs³³ and would not be supported by wholesale electricity price signals and avoided distribution network capex alone
- stimulating investment in generation where this is not supported by wholesale electricity prices, avoided distribution network capex, and reliability benefits alone
- changes in dispatch i.e. increasing production from embedded or notionally embedded generators to reduce net demand.

The pass-through of RCPD pricing signals to embedded generators, through ACOT payments, has meant there are stronger incentives and greater rewards for embedded generation *after* investment in transmission capacity. The Authority has shown payments to embedded generators may create a number of inefficiencies, without providing the benefit of delaying transmission investment or reducing overall delivered energy costs to consumers (it estimates the cost of ACOT to be \$10 per household per annum).³⁴

5.3.3. THE BENEFIT THAT N=12 MAY BE PROVIDING IN THE UNI REGION

As discussed in Section 4, there is a benign outlook for demand-driven investment in the UNI region. The Authority’s PDWP estimates deferral benefits in the range from \$5 to \$15m (NPV) associated with investment in series capacitors and shunt capacitors in the UNI region. In our view, this overstates the likely deferral benefits because the capacitor investments are likely to be progressed as economic investments.

Although the series capacitor investment would eventually be required for reliability reasons it is the economic benefits from reduced transmission losses that are driving the need date. Where the benefits are very close to the costs of an investment then the deferral value will be small. This is because the deferral value of economic investments equals:

$$(\text{investment benefit} - \text{investment costs}) \times \text{the deferral period}$$

Additional considerations are:

- the price signal provided by N=100 is likely to continue to stimulate a significant ongoing response
- nodal prices signal transmission loss and constraint costs

³² Norske Skog, Submission on the paper titled “Transmission pricing methodology: Problem definition relating to interconnection and HVDC assets”, 28 October 2014, page 3.

³³ Recognising for many large consumers this demand shifting may have little or no cost (as noted by Norske Skog and PanPac in submissions to our initial consultation)

³⁴ Electricity Authority, Working Paper, Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation, 19 November 2013, paragraph 1.15.

- if the outlook does change (e.g. due to further withdrawal of thermal plant from the UNI region or rapid demand growth) then we retain the option to strengthen the price signal and/or to utilise Transpower's demand response programme as a fast and targeted deferral option.

Overall, we consider that setting N=12 for the UNI region no longer provides any useful signal.

5.3.4. THE BENEFIT THAT N=12 MAY BE PROVIDING IN THE USI REGION

There are potentially two material investments in the foreseeable future that could be affected by reducing peak demand in the USI region:

- a switching station at Orari, in south Canterbury, with a forecast need date of between 2022 and 2028 on current forecasts. This investment has a deferral benefit of approximately \$4m PA (at the time of the investment in the 2020s)
- a new Islington line with a forecast need date of sometime after 2040. This investment has a deferral benefit of approximately \$65m PA (at the time of the investment in the 2040s).

Given the investment outlook, a strong transmission pricing signal in the medium term is likely to be of greater benefit in the USI region than in the UNI region. However, our overall view is that the benefit of the current signal is unlikely to be material. In particular:

- as with the UNI region the price signal provided by N=100 is likely to continue to stimulate a significant ongoing response (we note Orion's comments in support of this point³⁵)
- nodal prices also signal transmission loss and constraint costs
- the option to reinstate a stronger price signal in future³⁶ and our demand response programme provides an alternative way of deferring investment.

5.4. OPTIONS WE CONSIDERED

The options we considered are set out below. Our draft proposals were to recommend options two and three.

Option	Description
1 N = 12 for UNI and USI	Status quo
2 N = 100 for UNI (preferred)	De-tune the peaking signal in the UNI region
3 N = 100 for USI (preferred)	De-tune the peaking signal in the USI region
4 N > 100	Set charges over more than 100 peak periods
5 Other tariff designs	For example, use an intermediate value of N, energy (MWh), monthly or seasonal peaks, weighted peak demand, etc.

5.4.1. N = 100 FOR UNI AND USI

The option of setting N = 100 for UNI was supported by Contact Energy, Genesis Energy, Mighty River Power, NZAS ("don't disagree"), Northpower, Orion ("Yes, provided it is also set to 100 for USI."), PanPac, Powerco, Trustpower (with transition), Unison ("Only if there are minimal quantitative impact on the allocations of transmission charges to the regions") and Vector.

³⁵ Orion, Transpower TPM Operational Review: second Consultation, 19 December 2014, paragraphs 7.

³⁶ We identified in our second consultation paper that it would be logical to review transmission price settings in 2017/18 as part of a five yearly planning cycle.

The option is setting $N = 100$ for USI, as well, was supported by fewer parties: Contact Energy, Genesis Energy, Mighty River Power, Orion, Trustpower (with transition), Unison, and Vector.

The only parties against were MEUG (on the basis that it should be left to the Electricity Authority), Norske Skog (at least for UNI) and WPI.

We have concluded this proposal would be to the long-term benefit of consumers because it would:

- Significantly weaken incentives for costly and inefficient peak avoidance while preserving a moderate signal that will continue to stimulate zero and low cost peak avoidance (which we assess as representing most of the current response by volume).
- Be straightforward to implement and, while it results in some changes to the allocation of interconnection charges these are very small and would be offset by even a small change in RCPD for the UNI and USI regions.
- Result in avoided costs over five years are \$10.6m based on the analysis provided in section 5.4.2 and Attachment D.

While aspects of our cost benefit analysis differs from the Authority and Castalia's, for which we believe the rationale is sound, the underlying approach is consistent.

- Removing some of the year-by-year volatility that has been apparent in recent years attributable to the twelve highest NI demands being recorded primarily in June in one year and in July in another year, etc.

5.4.2. $N = 100$ FOR UNI AND USI: COST BENEFIT ANALYSIS

We have considered different ways to quantify the costs and benefits of changing from $N = 12$ to $N = 100$ for the UNI and USI RCPD regions. We consider that the Authority's approach in the PDWP provides a useful framework however we had difficulty developing the model to accurately reflect real world conditions, principally because we do not have empirical data needed to accurately model responses.

Therefore, the approach we have adopted for our CBA is to describe how different types of response are likely to change and then to draw on a few data points to produce an indicative assessment of the costs and benefits of the change.

The effect of diluting the price signal by increasing N from 12 to 100

What will change when N is increased to 100 for UNI and USI is an empirical question. However, all things being equal, we expect that changing N from 12 to 100 would result in:

- Reduced investment in responses with high and medium capital costs, such as standby generation. The effect on embedded generation investment will depend on plant characteristics, ACOT policy and interpretation.
- Reduced utilisation of sunk investments with high SRMC, such as diesel peaking generation (utilisation of sunk investments with medium and low SRMC investments may continue for the economic life of the asset (or, if leased, for the duration of the lease contract)).
- Reduced utilisation of low or no fixed cost but high or medium SRMC peak avoidance activity, such as peaking by embedded generation, curtailed production or costly production adjustments.
- A change in the utilisation of low cost responses such as hot water ripple control and low cost load shifting by larger loads; for example to target a larger number of peak periods (i.e. to deploy peak avoidance resources more thinly across a larger number of periods).

The figures below illustrate the expected response for different combinations of response (green: ongoing activity, orange: declining activity, red: no activity).

N = 12 setting

High fixed + High variable	High fixed + Low variable
Low fixed + High variable	Low fixed + Low variable

N = 100 setting

High fixed + High variable	High fixed + Low variable
Low fixed + High variable	Low fixed + Low variable

For the purposes of this analysis we assess the net effect as an increase in N in the difference between the top 12 peaks and the top 100 peaks and an increase in peak load.

To estimate the size of this increase we compared the N = 12 and N = 100 regions. Using 3 years' CMP data³⁷ (net of Tiwai constant load for LSI) we revised the RCPD figures for UNI and USI by scaling them by the (average) ratio for LNI and LSI. We found that:

- the average ratio for UNI and USI is 1.016 (i.e. RCPD at 12 is 1.6% higher than at RCPD 100).
- the average ratio for LNI and LSI is 1.038 (i.e. RCPD at 12 is 3.8% higher for RCPD 100).

We infer from this that peak demand, measured across the top 12 peaks, could increase by 2.2% for USI and UNI relative to current peaks if N were set to 100 (for our analysis we adopt a range from 1% to 3%). We recognise that this is but one way of estimating total load response, and that there may be structural differences between the two regions, but consider it to be plausible and in the range identified by the Authority.

In terms of MW reduced peak avoidance, this translates into:

RCPD region	Lower bound	Upper bound	Point estimate
UNI	19.1	57.4	42.1
USI	10.01	30.3	10.1

Estimating the benefits of changing to N = 100 in UNI and USI

As outlined above, we would expect changing N to 100 to render certain types of response uneconomic and have an immediate effect on prospective investments. The table below presents an analysis of the potential avoided cost for UNI based on the point estimate above, an allocation between response type, its variabilised cost and success rate.

³⁷ CMPs 1112, 1213 and 1314

	UNI – point estimate		MW	Variabilised cost per MW ½ hour	Responses per CMP (25% success rate)	Total cost
1	High fixed + high variable (e.g. low capacity factor diesel peaker)	70 %	29.5	\$1500	48	\$2.127 m
2	Low fixed + high variable (e.g. medium capacity factor standby generation)	15 %	6.3	\$500	48	\$.152M
3	High fixed + low variable (e.g. high cost industrial process change)	15 %	6.3	\$500	48	\$.152M
4	Low fixed + low variable (e.g. EDB ripple control, low cost industrial load shifting)	0%	-	-	-	-
	Total					\$2.43m

For UNI we assume the lower bound of the range (19.1MW) in year one and levelling off at the point estimate (42.1MW) in year two. The 5 year PV of avoided costs for UNI is \$8.47m. For USI we assume the lower bound of the range (10.1MW) from year one onwards with a five year PV of avoided costs for USI of \$2.1m for USI. Total avoided costs over five years are \$10.6m.

We recognise that this analysis is subjective but consider that it provides a reasonable assessment of benefits available from changing to N = 100 in UNI and USI.

In addition to avoided deferral costs some rebound in energy consumption and economic activity is likely. We have not quantified this benefit though consider it may be significant.

Estimating the costs of changing to N = 100 in UNI and USI

1. Increased avoidance costs

Changing N to 100 in UNI may cause some parties to undertake additional peak avoidance activities. This was recognised by the Authority in its problem definition analysis. While we do not disagree that more peak avoidance may occur we consider it unlikely to trigger significant increases in peak avoidance costs:

- The bulk of peak avoidance activity is now and is likely to continue to be made up of distributor use of ripple control (hot water). This resource is primarily used by EDBs for deferring distribution network investment and, while the resource is finite, the incremental cost of each action is likely to be close to zero³⁸
- Direct connect parties and those on pass through tariffs are expected to manage production / maintenance schedules as they do today. We note comments by Norske Skog and PanPac regarding the costs they incur to avoid peaks to both the Authority and Transpower on this subject.
- We expect medium sized commercial entities with standby generators or load curtailment capability to carefully consider whether the payoff available warrants the cost (we may see a

³⁸ A proxy for the SRMC of ripple control could be IL. Cleared prices for IL (FIR and SIR) are less than \$0.1 approximately 67% of the time.

similar level of activity targeted at the easiest to pick peaks). The change in response will depend on a number of factors, for example

- the quantum of payment / discount available: a function of marginal price (usually a function of distributor tariffs rather than the TPM) and the firms' success rate in targeting each peak
- cost: SRMC for firms who require standby generation capability (SRMC may be the cost of the fuel + transaction costs, or less in some cases if generator testing and or fuel needs to be refreshed periodically) and LRMC for firms who do not require standby generation (we adopt the Authority's \$3000 per MWh estimate)

We consider that the response, in terms of increased avoidance behaviour, is likely to be particularly small in the USI due to the extensive load control activity already undertaken by Orion and other USI distributors. This activity already extends well beyond the top 100 peaks.

2. Decreased transmission deferral benefits

We note that the change in peak avoidance (predominantly dedicated peaking generation plus some utilisation of standby generation and costly load responses) is expected to represent a relatively small proportion of total peak avoidance but to be (1) the most costly avoidance activity (2) able to be brought to bear in relatively short timeframes.

Altering the price signal at this point will reduce high cost peak avoidance costs at the point in time when it yields no transmission deferral benefit but, provided price signals are strengthened again closer to the investment need date, will have no effect on the available transmission investment deferral benefit.

5.4.3. N=100 FOR THE UNI REGION ONLY (OUR SECOND PREFERRED OPTION)

The option of setting N = 100 for UNI had more support than setting N = 100 for both UNI and USI.

Support UNI N = 100 only	Support UNI and USI = 100	Support neither
NZAS ("don't disagree"), Northpower, PanPac, Powerco.	Contact Energy, Genesis Energy, Mighty River Power, Orion, Trustpower (with transition), Unison, and Vector.	MEUG (on the basis that it should be left to the Electricity Authority), Norske Skog (at least for UNI) and WPI.

We consider the benefits of setting N = 100 for UNI to be greater than for USI on the basis that:

- UNI has now undergone a substantial upgrade in transmission capacity, which has alleviated the need for further substantial transmission capacity upgrades in the foreseeable future.
- The situation is different in USI. While incremental upgrades have increased capacity further expansion is forecast to be needed in the medium term (mid 2020s). If demand growth is higher than presently forecast this could bring forward the need for further transmission investment (accepting that, if demand forecasts did increase significantly, a stronger RCPD signal could be re-introduced).
- EDBs manage load for a variety of reasons and load management approaches differ between EDBs. While load management is evident in the UNI and the USI the comparatively aggressive load management in USI appears to be primarily for distribution network management reasons with transmission price avoidance a secondary objective. This may limit the effect of diluting the

transmission price signal.³⁹

Balancing this, incentives may be weaker for USI distributors to coordinate load control when regional peaks are expected to occur.⁴⁰ We have no reason to believe that this coordination will not continue but, because the price impact of missing one RCPD peaks is ~87% less at N=100 peaks than at N=12 peaks, we would expect individual EDBs to target RCPD peaks less aggressively. This assessment aligns with feedback we received anecdotally (though not in formal submissions).

5.4.4. RCPD CHARGES: N > 100 OPTION

We identified this option in our July consultation. The PDWP also identified the possibility that N = 100 may be encouraging inefficient peak avoidance (though it recognises that the low cost of avoidance will limit the magnitude of any inefficiency).

Our main reservations about this option are:

- changing to a setting above 100 would be a reasonably significant departure from established expectations and would require a greater degree of analysis and signalling than has occurred to date
- submitters on our initial consultation paper were not supportive of setting N>100 (see below)
- the main low-cost demand response technologies may not be able to respond to a number of peak half hours significantly in excess of 100, so the value invested in this capability would be undermined to some extent
- setting charges over a large number of peak half-hours would start to shift the signal from peak avoidance to uneconomic energy conservation. In other words, N=100 is a relatively neutral setting.

One of the messages from the submissions, particularly from major users, was that it was desirable to retain some level of ongoing peak usage signalling. We acknowledge the lack of support for N > 100. Representative excerpts from submissions include:

Contact Energy: We believe 100 peaks are sufficient. We believe that 100 peaks has a reduced signal when compared to 12 peaks, however network companies will still use the load management systems that they have invested in to manage to the 100 peaks which is in the commercial interest of their customers.

Mighty River Power: We would not recommend stepping above N = 100.

Powerco: In our view, the UNI "N" should be amended to 100.

However, we do not agree that increasing the "N" to more than 100 is necessary or that to do so would be efficient. Analysis undertaken by Transpower in 2006 showed that demand peaks level off at about N=100, so, if a customer is choosing to control load at that level of "N" (probably irrationally, because the lost benefits from the load control are likely to exceed the transmission cost savings), further increasing the N would be unlikely to have any material effect on that behaviour. Also, as the "N" increases, the interconnection charge would increasingly resemble a per kWh charge, which could then have an inefficient effect on energy consumption and investment decisions by those customers that see the transmission charge separately.⁴¹

Trustpower: We suggest that N=100 is a sufficient number of peaks for regions in which RCPD charges are not intended to send peak pricing signals. Therefore, a review would not be required.⁴²

Vector: ...Vector would not support an increase in the number of RCPD periods beyond 100 in the UNI without

³⁹ Orion, 2014/15 TPM Operational Review: second consultation paper, submission, page 2.

⁴⁰ For details see: <http://www.oriongroup.co.nz/load-management/Upper-south-island-load-management.aspx>

⁴¹ Powerco, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, response to Question 6.

⁴² Trustpower, Transpower TPM operational review, 5 August 2014, Appendix A: Response to consultation questions, paragraph 6.1.

further analysis, and compelling evidence that change is warranted, because: ... a) such a change would be material and is unprecedented; and ... b) as far as Vector is aware, there is no evidence that suggests more than 100 RCPD periods are required in the Upper North Island.⁴³

CarterHoltHarvey: The present size and investment in the existing transmission system is in general as a result of the need to accommodate historic peak consumption throughout the system ... In our view therefore, RCPD charges should always provide sufficiently strong peak pricing signals to ensure that consumers are aware of the consequences that high peak usages can have on potential future costs and have had on the present cost of the transmission system.⁴⁴

On balance, we do not support any N>100 options at this time. We prefer a more predictable, incremental approach to change, and changing UNI and USI to N=100 now does not preclude changing to N>100 in future if compelling evidence emerges.

5.4.5. RCPD CHARGES: OTHER TARIFF DESIGNS (NOT PREFERRED)

In our view, the TPM Guidelines would permit a range of tariff options. For example, we could set charges based on:

- setting N at an intermediate value between 12 and 100
- energy consumption (MWh) rather than peak demand
- anytime maximum demand, rather than coincident demand
- peak demand or energy during winter months only
- ‘weighted’ peak demand (for example, a weighting factor could be applied to South Island demand to ‘tilt’ the price signal towards the North Island).⁴⁵

We have not analysed any of these options in detail. In our view, they all suffer from the problem that they are too novel or unexpected to be introduced from 1 September 2015. The submissions we received on the second consultation paper did not elicit any support for these options, or reasons to consider them further.

It could be argued that we should hold off making a recommendation until we have examined all of the potential options and determined whether there are any options that are better than our current preferred options. We do not favour this approach because:

- our current preferred options can address a problem now, whereas pursuing other options would be likely to leave the existing problems intact for at least another year
- any of the other options would be novel in the New Zealand context and would be likely to require a phase in period, exacerbating the forgone benefits problem above
- we are proposing ‘no regrets’ changes that do not preclude further evolution of tariff design if it becomes clear that there is a more optimal option
- at this stage, our judgement is that it would not be possible for us to establish strong empirical evidence that any alternative tariff design would be materially better than what we are proposing.⁴⁶

⁴³ Vector, Transpower TPM Operational Review: Initial Consultation, 6 August 2014, Appendix A, response to Question 6.

⁴⁴ CarterHoltHarvey, Initial consultation feedback on possible TPM operational changes, 8 August 2014, page 2.

⁴⁵ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 5.5.4.

⁴⁶ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 5.5.4.

5.5. DEFINITION OF PRICING REGIONS

In our second consultation paper we proposed to merge UNI, LNI and LSI (or LNI and LSI, if the proposal to set N = 100 for UNI was rejected). Our main rationale for this proposal was:

- As identified in our July paper, there is a potential problem with unstable price signals in the LSI and high marginal price signal for the NZAS's smelter in the LSI region. These problems arise because the smelter is large relative to overall demand in the LSI region and the smelter has recently shifted a pot line into a 'swing demand' role.
- Having reached a view that it is preferable for all of the current regions to have charges set over the same number of peaks (i.e. N=100) it make sense to review whether to maintain the regions at all.

We also noted that, as demand on the transmission grid grows it may be appropriate to adopt different regions in the future e.g. it could be desirable in the future to aggregate GXP's north of Whakamaru (the southern terminal of the NIGU lines) rather than Huntly. There is no reason to expect any future regional split should be the same as the current regional split.

We also considered a single region (with charges based either on RCPD or anytime maximum demand (AMD)). We rejected the option of full amalgamation on the basis "there may yet be some deferral benefit from reducing USI peak demand" and "If charges were set on the top 100 nationwide peak demand periods then, based on analysis of the 2013/14 capacity measurement period, only 21 of the charging periods would correspond with USI peak periods. In other words, there is a relatively low correlation between USI peaks and national peaks".⁴⁷

5.5.1. SUBMITTER FEEDBACK

Contact Energy, Genesis Energy, Mighty River Power, Northpower (qualified), NZAS, Trustpower, and Vector all supported our contention that "all regions where N = 100 should be amalgamated into a single region unless there are clear rationale for not doing so". Orion, Powerco and WPI did not. Meridian was of the view this was not a matter we should be considering, and should be left to the Electricity Authority's TPM review.

Concerns raised about the proposal to amalgamate UNI, LNI and LSI (or all regions) included: (i) a preference for a bespoke solution to issues with NZAS; (ii) concerns about weakening the link between demand response and regional peaks; and (iii) the appropriateness of considering merging regions in light of the Electricity Authority's own TPM review.

5.5.2. OUR ASSESSMENT

We recognise concerns expressed by stakeholders in relation to our draft proposal and make the following observations:

1. While the NZAS swing load issue was just one of the reasons for considering merging the regions we did recognise that a bespoke NZAS solution has merit and "One option might be to set a bespoke capacity measurement period for NZAS (which excluded the seasonal production period)"⁴⁸ which we are now proposing.⁴⁹
2. We agree that RCPD regions, where defined, should reflect future investment needs and establish a clear link between demand response and regional peaks. The point we are less clear

⁴⁷ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 6.5.1.

⁴⁸ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 6.5.3.

⁴⁹ Refer to section 7: Proposed summer peak exclusion for LSI RCPD charges.

on is whether the current regions, with the exception of LSI, continue reflect future investment needs - or whether different regions may do so.

3. We agree that there is uncertainty around the timing and outcome of the Authority's TPM review, of which interconnection charges are a key issue. For example, the types of changes the Authority has signalled – such as locational pricing, LRMC pricing, beneficiaries-pay and zonal – would result in greater regional disaggregation/discrimination not less.

We are also mindful that the benefits associated with these proposals accrue in the medium to longer term and that some of the benefits sought through these proposals may be achievable through other means⁵⁰. This has two implications for the analysis, first, that the cost of not proceeding now is relatively small and second, that the benefits of proceeding now are relatively small.

While we consider RCPD regions require further consideration, perhaps (if still relevant) once the outcome of the Authority's review is known, we have decided not to proceed with our draft proposal at this point.

⁵⁰ For example, the LSI problem is addressed directly by proposal 2 and aggregating regions is not necessarily a prerequisite for more targeted RCPD regions.

6. NZAS RCPD SUMMER LOAD LIMIT

We propose that the regional demand data for NZAS (connection location TW12001) is amended to disregard load greater than 572MW up to and including 636MW, between 1 November and 30 April.

We do not consider that a phasing in period is warranted and propose this change be implemented for the CMP beginning 1 September 2015.

6.1. PROBLEM DEFINITION

NZAS consumes a large proportion of total electricity supplied in the LSI (averaged 67% in the year) which means a relatively small change in its demand behavior affects when the 100 regional peaks used to set transmission charges occur. This affects the incidence of charges for all users in the region and reduces the predictability of transmission charges.

The ability to change the incidence of the LSI RCPD peaks and subsequent charges can affect NZAS' consumption decisions. For example, NZAS considered increasing production from late spring 2014 to early autumn 2015 (and, likely, in subsequent years). While this would not affect transmission investment requirements it would shift some of the LSI regional peaks into the summer period making the production increase less economic.

NZIER⁵¹ and the Authority⁵² have considered this problem. We have adopted the Authority's assessment of the efficiency impact of the current RCPD charges on the NZAS smelter; that assessment is:

"The interconnection charge may inefficiently deter the Tiwai smelter from seasonally varying its production. This may result in productive inefficiency in the range of \$4M–\$32M PV."

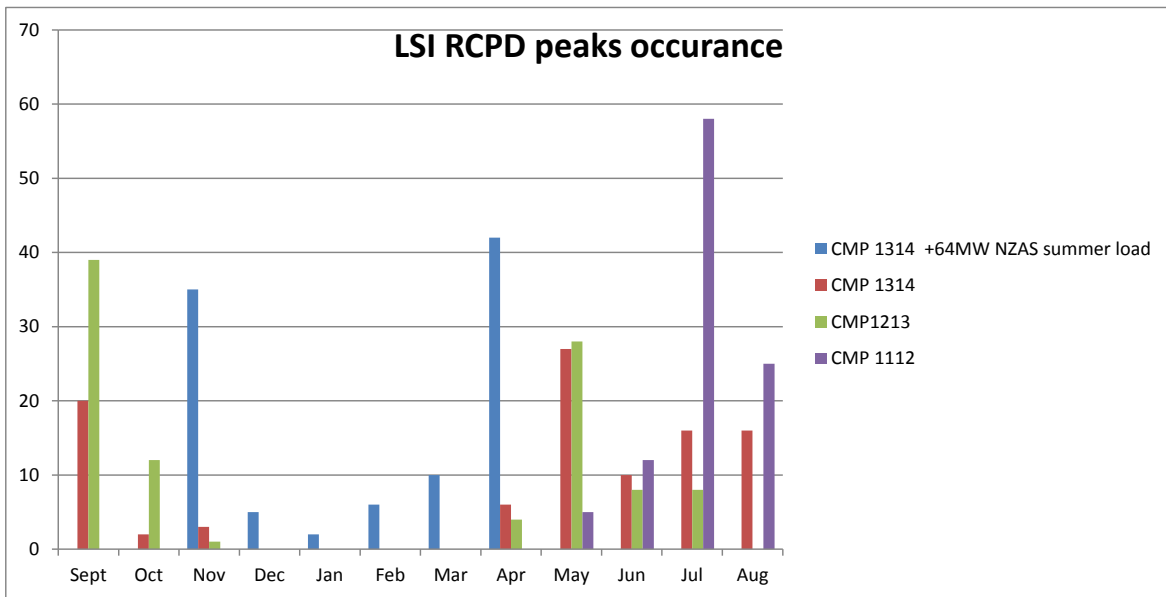
We also agree with NZIER's analysis that the effect of the 64MW increase is to shift the majority of LSI RCPD periods into the summer months, with consequent impacts to others in the LSI through the greater allocation of charges under RCPD.

Figure 6 illustrates that the LSI RCPD peaks are usually in the winter months, but with a 64MW increase in NZAS consumption through summer all the peaks move to the summer months.

⁵¹ NZIER report to NZAS, Accommodating load growth: amending transmission prices to avoid inefficient demand loss, March 2014.

⁵² September 2014, TPM review: problem definition working paper

Figure 6 Timing of LSI RCPD peaks with and without NZAS additional summer production



6.2. OPTIONS WE CONSIDERED

Our Initial and second consultation papers proposed amalgamating the UNI, LNI and LSI regions into one region (which was previously our preference), amalgamating all four regions or adopting a bespoke option for NZAS. While we consider that amalgamating regions has merit, we have decided not to proceed with this proposal, pending the outcome of the Authority’s TPM review.⁵³

Several submitters suggested separating NZAS into its own region. We have decided not to proceed with this option either because it would not address the seasonal production problem without additional changes to RCPD settings.

The other option we identified in the second consultation paper is “to set a bespoke capacity measurement period for NZAS ...”.⁵⁴ We consider that, if RCPD regions are not amalgamated, this would be the cleanest and most effective solution. However, rather than a blanket exclusion of the six month period we proposed to only exclude the incremental 64MW production.

The Authority modeling estimates addressing the smelter issue could have productive efficiency benefits in the range of \$4M–\$32M PV.⁵⁵ NZIER similarly estimates the benefits from resolving the smelter issue to be between \$9 million and \$40.4 million (present value over 3 years).⁵⁶

6.2.1. ASSESSMENT OF COSTS AND BENEFITS

Costs

We do not anticipate there would be any incremental costs to Transpower to implement this proposal. We expect the Authority may incur modest incremental costs to process this Code change proposal (and will be incurred regardless of whether the proposal is accepted so should not affect the CBA).

⁵³ Refer to section 6.5: Definition of pricing regions.

⁵⁴ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 6.5.3.

⁵⁵ Electricity Authority, PDWP, 16 September 2014, paragraph 11.75.

⁵⁶ NZIER report to New Zealand Aluminium Smelters Ltd, Accommodating load growth: Amending transmission prices to avoid inefficient demand loss, March 2014.

We have reviewed the impact of a change to a summer peak on LSI on the transmission system and can confirm it would not create any capacity constraints or need for additional investment. We recognise that this may change in future and propose to review this provision as part of any future clause 12.85 reviews that Transpower undertakes.

Benefits

We note that the Authority estimates addressing the smelter issue could have productive efficiency benefits in the range of \$4M–\$32M PV.⁵⁷ NZIER similarly estimates the benefits from resolving the smelter issue to be between \$9 million and \$40.4 million (present value over 3 years).⁵⁸

We recognise that the true benefit of addressing this problem with the TPM is difficult to estimate with any degree of accuracy. We have no reason to believe that the true benefit should fall outside the range of benefits estimated by the Authority and NZIER.

⁵⁷ Electricity Authority, PDWP, 16 September 2014, paragraph 11.75 (and TPM problem definition modelling Excel sheet).

⁵⁸ NZIER report to New Zealand Aluminium Smelters Ltd, Accommodating load growth: Amending transmission prices to avoid inefficient demand loss, March 2014.

7. HVDC COST ALLOCATION

We propose to replace the current allocator for HVDC costs, the historic anytime maximum injection (the HAMI charge), with an allocator based on the mean energy injected by South Island generators into the grid.

We propose to phase in the MWh charge in way that (a) eliminates any HAMI related incentive effects from 1 September 2015 (b) preserves price stability during the transition period (c) avoid unproductive wealth transfers and (d) is fairly straight forward to implement.

7.1. PROBLEM DEFINITION

There is clear evidence the HAMI charge is causing South Island generators to withhold capacity to avoid attracting a greater share of HVDC costs. This reflects the very high marginal cost to generators associated with setting a new peak. Scientia Consulting estimate the incremental cost of increasing South Island generation injection by 1kW to be as high as \$44,600 for a generator with little or no existing South Island injection (it will be lower for generators who already attract HAMI charges because increasing HAMI reduces the HVDC rate).⁵⁹

As set out in the Section 4, the strength of the HAMI price signal has increased by more than 60% since 2008/09 (in real terms) due to investment in the Pole 3 convertor stations, and upgrades to the Pole 2 control systems.

The two largest South Island generators have confirmed they withhold generation to avoid HVDC charges.

Contact Energy's submitted

...the use of the half-hour anytime maximum injection charge (HAMI charge) to determine the HVDC charge discourages Contact from operating South Island generation at full capacity. Contact's possible peak output is 464MW at Clyde and 320MW Roxburgh, however, the current optimal maximum output to support the HVDC charge has been determined by Contact to be ~400MW at Clyde and ~278MW at Roxburgh, generation which is significantly below our peak output. Since 2008 we have not offered above these HAMI limits except under Exceptional Operating Conditions (EOC).⁶⁰

Meridian's submission on the Authority's PDWP states

...Meridian has a standing policy to withhold capacity when a generation plant may set a new HAMI limit. Meridian is careful in observing this policy, as new a HAMI limit at any generation plant will incur a corresponding increase in HVDC liability, which will take 4 years to clear based on current HAMI calculations.⁶¹

In addition to influencing operating decisions, the HAMI charge influences decisions on incremental capacity upgrades e.g. as part of periodic turbine replacement projects, or where there are opportunities for small enhancements to existing hydro schemes.

7.1.1. SUBMISSIONS FEEDBACK ON THE HVDC PROBLEM DEFINITION

The submissions we received on our assessment of the problems with the current HAMI charges confirmed our concerns; specifically, that: (i) the HAMI charges result in withholding of generation capacity by South Island generators; (ii) various reviews of the HAMI charges (TPAG, Electricity

⁵⁹ Refer Appendix A

⁶⁰ Contact Energy, Re: Transpower TPM operational review: initial consultation paper, 8 August 2014, page 1.

⁶¹ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, response to Question 13.

Authority and Transpower) have all identified this as a problem; and (iii) while the inefficiency is relatively small (“Up to 3% of the PV of HVDC revenue (on PDWP analysis)”⁶²) it is worth investigating.

Mighty River Power noted “... we support the problem definition”⁶³ and “... have no reason to question the evidence provided in successive TPM reviews to date by other generators”.⁶⁴

The ENA agreed “... an operational issue has been identified in terms of transmission charges causing generators to withhold capacity”.⁶⁵

South Island generators, Meridian Energy, Contact Energy, Pioneer Generation and Trustpower provided details of how the HAMI charges impacted on their operation of South Island generation:

Meridian's current HVDC charge is approximately \$50,000 MW/p.a. This cost is substantial, and consequently Meridian's operations are constantly concerned with controlling the HAMI limit at each generation connection location. Specifically, Meridian has a standing policy to withhold capacity when a generation plant may set a new HAMI limit ... Discourage upgrades to SI generation capacity ... Brings forward the need for investment.⁶⁶

... As Contact has already noted in our submissions on the TPMs, the use of the half-hour anytime maximum injection charge (HAMI charge) to determine the HVDC charge discourages Contact from operating South Island generation at full capacity. Contact's possible peak output is 464MW at Clyde and 320MW Roxburgh. However, the current optimal maximum output to support the HVDC charge has been determined by Contact to be ~400MW at Clyde and ~278MW at Roxburgh, generation which is significantly below our peak output. Since 2008, we have not offered above these HAMI limits except under Exceptional Operating Conditions (EOC).

While in the past transmission limitations and the HVDC charging regime have limited the capacity offered at Clutha, recent significant improvements to transmission capacity (HVDC, ROX T10, ROX SPS) mean that going forward the limitation is solely the HVDC charging regime. While Contact has and will continue to review whether our HAMI limit is set at the optimal level, any changes will be only incremental changes unless the charging regime changes.

The Clutha run of river generation as provided in the consultation can peak another ~108MW, which is a significant proportion of the benefits that can be realised with moving away from a HAMI arrangement.⁶⁷

We actively manage generation ... by withholding our renewable generation at CYD, which frequently results in spilling (both water and wind).⁶⁸

It is worth noting that the current HAMI charge acts as a disincentive to investment not just in peaking generation, but also inflexible intermittent generation with relative low load factors. Wind farms, for example, only generate at more than 90% output for less than 15% of the time ... These assets are therefore disproportionately impacted by HAMI charges per MWh of output.⁶⁹

HAMI charges have been a consideration in the delay of our potential investments [sic] new power stations at Arnold and Wairau, which are consented for development ...⁷⁰

⁶² Transpower, Transmission pricing methodology: problem definition working paper, 28 October 2014, Appendix: Our assessment of the key concerns expressed in the PDWP.

⁶³ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, response to Question 13.

⁶⁴ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, response to Question 14.

⁶⁵ ENA, Submission on Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets, 28 October 2014, paragraph 15.

⁶⁶ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, response to Question 13.

⁶⁷ Contact Energy, Re: Transpower TPM operational review: consultation paper, 19 December 2014, page 2.

⁶⁸ Pioneer Generation, Re: Transpower's operational review of the transmission pricing methodology, 19 December 2014, page 2.

⁶⁹ Trustpower, TRUSTPOWER SUBMISSION: TRANSPower TPM OPERATIONAL REVIEW SECOND PAPER, 19 December, response to Question 13, paragraph 13.1.

⁷⁰ Trustpower, TRUSTPOWER SUBMISSION: TRANSPower TPM OPERATIONAL REVIEW SECOND PAPER, 19 December, response to Question 14, paragraph 14.1.

NZIER cautioned "We were previously of the opinion that TPAG overstated the costs that stem from the HVDC charges under the TPM and we believe that the Authority and now Transpower agree with this view. While we have sympathy with the arguments about the possible effects of the HVDC charges on potential withholding of capacity, we believe that the costs, if they exist, are likely to be very small".⁷¹

Genesis Energy also provided the following qualification to the extent of problems with the HAMI charges:

Genesis Energy is not convinced that the HAMI charge has resulted in reduced generation capacity for the South Island. Rather we suggest that the HAMI charge is more likely to impact on the operational decisions on existing generation assets.

Transmission costs are simply one factor to be considered in a new investment decision. We suggest that other factors, such as access to available fuel or resources for generation, demand forecasts, and consumer growth patterns are likely to be more relevant to these decisions.⁷²

7.2. OPTIONS WE CONSIDERED

We have recommended option three to the Authority: and energy tariff based on the previous 5 years MWh generation. This differs from our draft proposals which were to recommend options two (with option three as a second preference) and five.

Option	Description
1 HAMI	Status quo
2 Diluted HAMI	Set charges based on the top N injections, where N is large.
3 Energy tariff	Set charges based on energy production (MWh)
4 Name plate	Set charges based on the physical capacity of installed plant
5 De-rate USI	Apply a weighting factor to reduce charges for USI generation

We engaged Scientia to simulate the impact of diluting the HAMI tariff by setting charges based on a relatively large number ('N') of peak injections.⁷³ We also asked Scientia to simulate the impact of changing to any energy (MWh) tariff, calculated on a similar multi-year basis to the current HAMI charge. The simulation technique is the same as used for the diluted HAMI option (a multi-year average is retained to reduce inter-year volatility that would otherwise occur due to hydrology).

Scientia's final report is enclosed at Appendix 1 to this paper, together with modelling instructions. The report describes changes made to the modelling approach to reflect customer feedback and on instruction from Transpower (to reflect modified proposals).

7.3. DILUTED HAMI vs MWh

In our second consultation paper we identified that, if N is a sufficiently large number, then the incremental transmission cost to a South Island generator from increasing injection becomes small relative to the incremental revenue from producing additional energy. Simulations by Scientia showed that, if N is sufficiently large:

⁷¹ NZIER memo to MUEG: Transmission pricing changes, 19 December 2014, paragraph 14.

⁷² Genesis Energy, Support for proportional changes to fix problems with current transmission cost allocation, 22 December 2014, response to Question 14.

⁷³ Scientia's initial report is included as Appendix 3 of Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014.

- more South Island hydro generation is dispatched during high-price periods, displacing North Island thermal generation
- load costs (i.e. market clearing prices) are reduced at these times
- ‘system’ costs (i.e. the total cost of dispatched energy assuming offers reflect costs) are reduced
- with very large N, the charge becomes close to an energy (MWh) charge and begins to have the effect of increasing load costs at low-price periods (i.e. because otherwise very low priced South Island generation is now factoring in the cost of transmission charges).

In addition to the diluted HAMI option, we identified that an energy tariff (MWh) would be likely to deliver similar economic benefit but would provide a much smaller consumer benefit. For this reason, an energy tariff was presented our second preference behind the diluted HAMI option (10,000 peaks).

7.3.1. SCIENTIA’S ANALYSIS

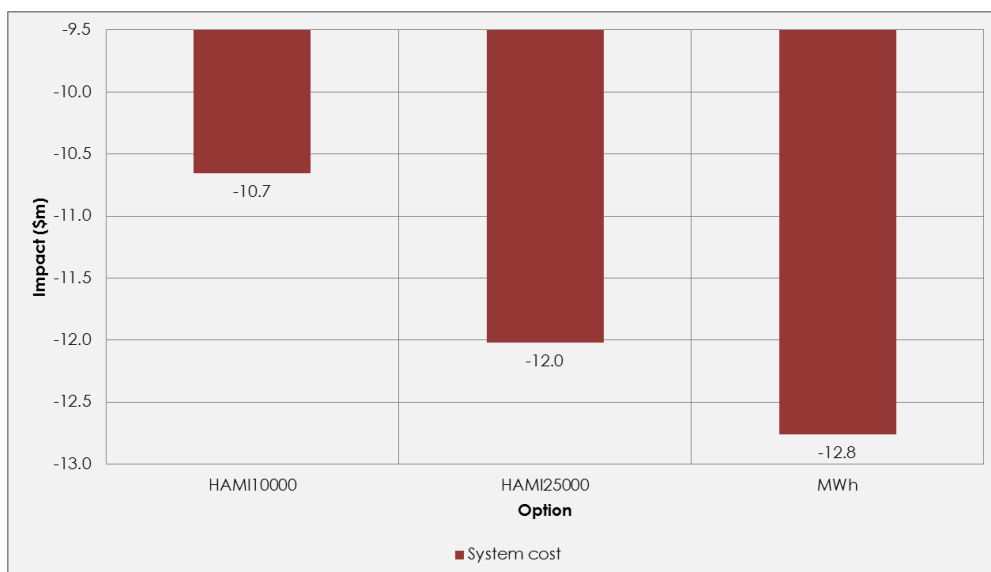
Since November Scientia’s analysis has progressed significantly, in a large part due to feedback from stakeholders. While efficiency gains (reduced system costs) have been relatively stable, load cost (and generator revenue) estimates have been shown to be quite volatile and have reduced markedly as the analysis has been refined. The main implications of this are:

- we are confident that the estimated efficiency benefits are robust and are likely to eventuate
- we are not confident that load cost (and generator revenue) estimates are robust and likely to eventuate

Although we initially considered factoring in consumer benefits that may accrue through reduced load cost (as this may indirectly result in efficiency gains) our concerns about the volatility of load cost results have led us to base our recommendation to the Authority exclusively on the basis of efficiency benefits.

The chart below shows Scientia’s final assessment of efficiency benefits expected to arise from two alternative diluted HAMI options and the MWh option.

Figure 7 System cost reductions: diluted HAMI vs MWh



7.3.2. SUBMITTER FEEDBACK ON DILUTED HAMI VS MWh

There was an overwhelming preference from our customers and interested parties for a MWh charge over a diluted HAMI charge. Orion was the only submitter that preferred a diluted HAMI charge, while Genesis Energy, Meridian, Contact Energy, Pioneer Generation, Mighty River Power, Powerco, and Trustpower all expressly stated support for a MWh charge. For example:

Genesis Energy:

We consider a MWh approach is preferable to the diluted HAMI for the South Island generators. Our preference is based on assessing the:

- practicability of implementing a MWh approach versus a diluted HAMI approach; and
- the risk of unintended consequences that arises from the HAMI charge – despite the intention to dilute the price signal for generators.⁷⁴

Meridian Energy:

We consider that the short-term distortions from a MWh allocation will be less than those from a MW allocation i.e. it is the least-worst of the options presented.

Contact Energy:

Under a diluted HAMI charge, Contact's offers will remain distorted; there will not be a material change to the Clutha peaking capacity. This is counter to the purpose of moving from the existing arrangement. During periods where the price is less than the SRMC of large thermal plant, capacity is still required to meet shortfalls that were previously covered by the large operational range of the thermal generation.

A MWh charge would enable additional SI generation to be made available to meet this need.⁷⁵

Pioneer Generation:

This is the simplest solution since: ... everyone knows the cost of injecting an extra MW into the transmission grid ... the same charge applies to all South Island generators for injecting an additional MW into the transmission grid ... everyone has the same information ... this method offers significant efficiency gains according to Transpower's analysis ...⁷⁶

Mighty River Power:

... we consider a MWh charge may end up being more practical given the uncertainties in the modelling versus the realities of the wholesale market, hydrology and refinements needed such as the management of river chains and hydrology, as highlighted by SI generators during the recent forum.⁷⁷

Powerco

The concept of a diluted HAMI charge ... is an interesting and theoretically attractive concept, as it seems to offer the advantage of avoiding the current incentive for South Island generators not to offer some capacity during high demand periods, while circumventing the problem with MWh-based HVDC charge will affect the generators' offer prices during periods of low demand and low prices (e.g. overnight). However, we suspect that, in reality, the diluted HAMI will be so similar to a per MWh charge that South Island generators will average it into their offer prices, which would negate its intended advantage. Hence, we are inclined to prefer a straightforward move to a per MWh charge.⁷⁸

⁷⁴ Genesis Energy, Support for proportional changes to fix problems with current transmission cost allocation, 22 December 2014, page 5.

⁷⁵ Contact Energy, Re: Transpower TPM operational review: consultation paper, 19 December 2014, page 1.

⁷⁶ Pioneer Generation, Re: Transpower's operational review of the transmission pricing methodology, 19 December 2014, page 2.

⁷⁷ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, response to Question 15.

⁷⁸ Powerco, Re: Transpower TPM operational review: second consultation paper, 19 December 2014, page 2.

7.3.3. OUR ASSESSMENT

Since reviewing the submissions on the second consultation paper, and in light of Scientia's final report, we have revised our view on diluted HAMI versus MWh.

We have decided to recommend that the Authority consider changing from allocating charges on the basis of HAMI to a MWh based energy charge:⁷⁹

- While there is potential for a diluted HAMI to get the 'best of both worlds' by maximising efficiency and consumer benefits, and this was the basis of our draft proposal, we are no longer confident of this outcome. On the contrary, the risk that a diluted HAMI produces the 'worst of both worlds' seems quite plausible if, for example, the optimal 'N' is not selected. We note that this was a key concern from stakeholders; for example:

"... the analysis carried out by Transpower to date is not sufficiently robust to determine an optimal N".⁸⁰

... a diluted HAMI charge will not result in a material change to our offer behaviour (i.e. lift from our current HAMI optimal level) and therefore will not resolve the security risks and price volatility during times where low thermal capacity is committed. These concerns can be overcome with a MWh approach.

We consider all of the options considered by Transpower as preferable to the current HAMI regime. However, we consider that the MWh allocation mechanism is likely to be less distortionary over time, and much easier to implement, than the diluted HAMI.⁸¹

- A MWh charge is expected to produce larger efficiency benefits than the diluted HAMI charge and, as established by the point immediately above, those efficiency benefits appear more likely to materialise for a MWh than a diluted HAMI charge.
- Finally, while we recognise TPM decisions should not be undertaken by 'vote', we consider the strong support for a MWh charge would be most consistent with ensuring the ongoing durability of the TPM: there is an overwhelming preference from our customers and interested parties for a MWh charge over a diluted HAMI charge (including from all of the affected South Island generators).

Injection data: pricing year vs capacity measurement period

HAMI charges are currently set using data from combination of pricing years⁸² (PY) and capacity measurement periods⁸³ (CMPs). This is somewhat confusing and results in overlap between the relevant injection periods for no observable benefit. As a result we propose to base future charges on CMPs rather than pricing years and CMPs.

The MWh charges would be set on the basis of the average of total injection for each generator across each of the *previous 5 complete CMPs*.

Is a transition needed?

In considering whether a transition period was required we considered the following objectives, in order of priority:

1. efficiency gains are achieved as soon as possible (from 1 Sept 2015) and minimises distortion created during the switch from HAMI to a MWh based charge
2. that inter-year stability is preserved

⁷⁹ Described as South Island Mean Injection (SIMI) in draft TPM regulations

⁸⁰ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, response to Question 15.

⁸¹ Genesis Energy, Support for proportional changes to fix problems with current transmission cost allocation, 22 December 2014, page 2.

⁸² 1 April to 30 March

⁸³ 1 September to 31 August

3. avoid wealth transfers where possible during the transition
4. is relatively straight forward for Transpower to implement and communicate to customers

We considered the following options:

	Option	Pros	Cons
1	Back-cast: transition straight to MWh (using injection data from previous 5 years)	Achieves intended efficiency outcomes + provides inter-year stability + simple to implement	Is retrospective + creates second order wealth transfers
2	Fresh start: transition straight to MWh (build up to 5 years injection data over time)	Achieves intended efficiency outcomes + simple to implement	Creates risk of inter-year volatility during transition + creates second order wealth transfers + longer implementation period
3	Staged transition: 4 year transition (where HAMI incentive free from 1 Sept 2015)	Achieves intended efficiency outcomes + provides inter-year stability + avoids wealth transfers + simple to implement	Longer implementation period

We consider that any of the options above would be acceptable (i.e. similar efficiency benefits are available with or without a transition period); however, we consider option 3 best achieves the objectives without any significant downsides. Option 3 also serves to dilute the incentive effect provided by the MWh charge during the transition (meaning efficiency benefits during the transition are likely to exceed modelled benefits). To be clear, our expectation is that the HAMI charge would cease to have any incentive effect from 1 September 2015 under all three options.

7.3.4. IS A TRANSITION NEEDED?

An issue we have identified with the proposals in the Second Consultation Paper is that it would result in an implicit transition period where South Island generators' injections would impact on both the HAMI charges and the future MWh charges. This could – temporarily – result in undesirable inefficiency (the worst of both worlds – the detriment of MWh without the full benefit of removal of HAMI).

As a consequence we have considered alternative transition options. We have concluded that there are a number of transition options that could ensure the benefits of moving away from HAMI are realised straightaway without any unintended inefficiencies.

In considering potential transition arrangements we considered the following objectives, in order of priority:

5. efficiency gains are achieved as soon as possible (from 1 Sept 2015) and minimises distortion created during the switch from HAMI to a MWh based charge
6. that inter-year stability is preserved
7. avoid wealth transfers where possible during the transition
8. is relatively straight forward for Transpower to implement and communicate to customers

We considered the following options:

	Option	Pros	Cons
1	Back-cast: transition straight to MWh (using injection data from previous 4 years)	Achieves intended efficiency outcomes + provides inter-year stability + simple to implement	Is retrospective + creates second order wealth transfers

2	Fresh start: transition straight to MWh (build up to 4 years injection data over time)	Achieves intended efficiency outcomes + simple to implement	Creates risk of inter-year volatility during transition + creates second order wealth transfers + longer implementation period
3	Staged transition: 4 year transition (where HAMI incentive free from 1 Sept 2015)	Achieves intended efficiency outcomes + provides inter-year stability + avoids wealth transfers + simple to implement	Longer implementation period

We consider that any of the options above would be acceptable (i.e. similar efficiency benefits are available with or without a transition period); however, we consider option 3 best achieves the objectives without any significant downsides. To be clear, our expectation is that the HAMI charge would cease to have any incentive effect from 1 September 2015 under all three options.

Proposed transition

We propose to adopt option 3 with the following transition:

Pricing Year		April 2017 – March 2018	April 2018 – March 2019	April 2019 – March 2020	April 2020 – March 2021
Four year transition (HAMI component is incentive free from 1 Sep 15)		75% HAMI	50% HAMI	25% HAMI	100% MWh
		25% MWh	50% MWh	75% MWh	
Pricing Years, (PY) and Capacity Measurement Periods ⁸⁴ (CMP)	HAMI	PY13/14 PY 14/15 CMP14/15 PY14/15 (to Aug 2015)	PY14/15 CMP14/15 PY14/15 (to Aug 2015)	CMP15/16 PY14/15 (to Aug 2015)	
	SIMI		CMP15/16 CMP16/17	CMP15/16 CMP16/17 CMP17/18	CMP15/16 CMP16/17 CMP17/18 CMP18/19

We consider that this approach will help ensure that:

- efficiency gains are achieved as soon as possible (from 1 Sept 2015)
- that inter-year stability is preserved (prices will draw on 4 years injection instead of the 3.5 years under the status quo)
- avoid unproductive wealth transfers during the transition
- changes are relatively straight forward to implement and communicate to customers

The transition we propose has the advantage of ensuring the HAMI charge is ‘incentive-free’ during the transition as it would be based on historic (up to August 2015) peak injections only. The MWh charge would be lower during the transition as well as it would not be recovering 100% of the HVDC revenue requirements so the costs of the MWh charge will be less than identified by Scintia for when the MWh charge is in full operation.

⁸⁴ Pricing Year is 1 April to 30 March and Capacity Measurement Period is 1 September to August

7.3.5. WHY WE ARE NOT PROPOSING INCENTIVE-FREE OR NAME PLATE CAPACITY CHARGES

This option did not elicit much further comment or evidence, beyond that provided in response to the Initial Consultation Paper.

The benefits of adopting incentive-free or name plate capacity HVDC charges were recognised in the NERA report for the New Zealand Electricity Industry Steering Group, New Zealand Transmission Pricing Project, 28 August 2009:⁸⁵

The potential benefits from switching to a capacity-based charge, in which HVDC charges are based on, say, nameplate capacity, is that the charge should in no way affect the usage/bidding decisions of generators (unlike an energy-based charge).¹¹⁷ For existing generation facilities, capacity will have already been established and, for new units, nameplate capacity will be established during commissioning. Such charges are reasonably commonplace internationally. The potential disadvantage of a capacity-based charge is that it does not address the incentives to eschew from investing in South Island capacity (particularly peaking capacity), although for the reasons explained above, this is not necessarily detrimental if North Island investment is to be preferred.

TPAG then undertook quantified analysis which determined it was the HVDC pricing option that would result in the greatest efficiency gains and consumer welfare improvements. TPAG assessed that incentive-free would result in an improvement in consumer welfare of between \$952 million and \$1,297 million in NPV terms. This compared to its assessment of postage stamp (-\$253 million to \$93 million NPV) and postage stamp transition (\$138 million to \$635 million NPV).⁸⁶

While TPAG considered the ‘incentive-free’ option produced the greatest efficiency and consumer welfare benefits, and considered it was “not entirely dissimilar to the postage stamp transition option”⁸⁷ supported by the majority of TPAG members, it nevertheless rejected it on the basis of “Strong reservations about arbitrary exercise of regulatory powers that would compromise good regulatory practice”⁸⁸ and the “negative incentives for incumbent SI generators to lobby actively to have the charge removed on the basis that it is unfair ... and arbitrary”.⁸⁹

The option was strenuously opposed by various, but not all, submitters in response to the Initial Consultation Paper. For example:

We support Transpower’s view that name plate ratings are not a preferred option for the reasons given. This would significantly discourage new investment in the South Island, especially those that have lower capacity factors.⁹⁰

We take particular objection to the “incentive free” option being included in this review. This option would represent a fundamental change to the TPM and should only be considered by the Authority (if at all). It is completely at odds with the Authority’s concerns to create a durable TPM and would amount to a “regulatory mugging”.⁹¹

We do not believe the “incentive free” concept is worth pursuing as no allocator is genuinely incentive free, e.g. even the use of nameplate capacity may encourage investments in new South Island plant to favour manufacturers whose nameplate capacities are known to be less than their true maximum generation capacities.⁹²

⁸⁵ NERA, report for the New Zealand Electricity Industry Steering Group, New Zealand Transmission Pricing Project, 28 August 2009, page 92.

⁸⁶ TPAG, Transmission Pricing Analysis, report to the Electricity Authority, 31 August 2011, Table 18.

⁸⁷ TPAG, Transmission Pricing Analysis, report to the Electricity Authority, 31 August 2011, paragraph C.4.2.

⁸⁸ TPAG, Transmission Pricing Analysis, report to the Electricity Authority, 31 August 2011, Table 2.

⁸⁹ TPAG, Transmission Pricing Analysis, report to the Electricity Authority, 31 August 2011, paragraph C.4.1.

⁹⁰ Contact Energy, Re: Transpower TPM operational review: consultation paper, 19 December 2014, page 3.

⁹¹ Meridian Energy, Transpower TPM operational review: Initial Consultation, 6 August 2014, response to Question 13.

⁹² Powerco, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, response to Question 16.

A charge based on nameplate capacity would be unlikely to be feasible ... Transpower assessed the practicality of a nameplate charge at length as part of its development of the current TPM in 2006. As discussed in section 4 of Transpower’s supplementary material to the 2006 TPM: ... “Guideline 15 only requires South Island generators to pay HVDC charges if they inject into the grid” ... and ... “Guideline 15 restricts the payment of HVDC charges to South Island generators that actually inject into the grid.” ... This suggests the only way Transpower could implement a charge based on nameplate capacity and still comply with the existing Guidelines would be for embedded generators to be directly excluded from paying HVDC charges altogether. While this option would be beneficial to parties that own embedded generation (such as Trustpower), it does not seem like a sensible option as some embedded stations do occasionally inject into the grid.⁹³

In our view, changing to name plate capacity would be a significant departure from current TPM settings. There is strong opposition to the option and it would be controversial. Given the benefits that can be obtained from our preferred, more incremental, options we do not favour the name plate capacity option.

7.3.6. WHY WE ARE NOT PROPOSING DE-RATED HVDC CHARGES IN USI

This option was introduced in the second consultation paper (it had not been identified as an option for the Initial Consultation Paper).

In the second consultation paper we outlined the reasons behind the option:⁹⁴

... the generation investment deterrent effect of the HVDC charge is potentially more harmful in the USI region than in the LSI region. This is because the USI is an importing region and may eventually require a new transmission line if demand growth continues to outpace generation growth.

Given this, we have considered whether we should apply a weighting factor to USI injection that would reduce the HVDC charge for USI generation. For example, if we used a weighting factor of 0.1 then a USI generator injecting 10 kW would attract the same HVDC charge allocation as a LSI generator injecting 1 kW.

... after the Cobb power station becomes embedded (in December 2014) there will be very limited grid-connected generation in the USI region – more than 97% of HVDC charges will be allocated to LSI generators. This means that the price impact of the change would be minimal with respect to existing generation capacity ...

... it is plausible that this change could deliver benefits. There are various generation development options in the USI region, and there is evidence that the HVDC charge currently has an impact on the viability of those options. For example, Meridian’s recent submission on the Authority’s PDWP observed “Meridian’s 60-70MW Hurunui wind farm was consented in 2013 and would be embedded, avoiding HVDC charges under the current TPM. However, the size (MW) of that wind farm has been limited by the decision to embed it i.e., the design may not make the best use of the wind resource, but does optimise the economics of the site given the transmission cost signals in place.” Reducing the transmission pricing deterrent to USI generation appears to be a low cost and low risk option for removing a potential inefficiency.

We decided against proposing this option for a number of reasons. The option to de-rate the HVDC charge in USI gained no support from submitters. It was expressly opposed by: Contact Energy, ENA, Genesis Energy, Meridian, and Powerco.

Reasons provided by submitters for their opposition included:

Contact does not support the proposal to de-rate the HVDC charge in the Upper South Island to 10% of the charge that other SI generators face. This diverges from the current TPM principle that the HVDC charge is applied to SI grid connected generation and is beyond the scope of the operational review, to reduce the HVDC charge in the USI for a HVAC purpose.⁹⁵

⁹³ Trustpower, TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, Appendix A: Response to consultation questions, paragraphs 13.5 – 13.7.

⁹⁴ Transpower, 2014/15 TPM Operational Review: second consultation paper, 13 November 2014, section 7.5.5.

⁹⁵ Contact Energy, Re: Transpower TPM operational review: consultation paper, 19 December 2014, page 3.

The ENA observes that the derating of USI generation in terms of the HAMI charge appears to be somewhat ad hoc and as such considers caution is warranted.⁹⁶

The proposed USI generator discount would amount to a cross-subsidy of USI generation by other South Island generators. We do not consider this represents good practice, and would prefer mechanisms that are more targeted to the specific capacity events. We encourage Transpower to consider other, market based, mechanisms for addressing capacity issues and defer USI capex expenditure. [footnote removed]⁹⁷

... the proposed 90% discount for HVDC charges for new generation in the USI is intended to encourage generation in the USI to reduce net demand and avoid transmission investment. However, the RCPD proposals aim to reduce the costs on demand in the same region, sending a signal to increase demand, which would bring forward transmission investment. These signals counteract, and may undermine the respective impacts of each change.⁹⁸

The idea of de-rating the HVDC charge by a factor of ten in the USI region seems a little too ad hoc to us and not adequately justified. There is also the possibility of ... challenge to such an allocation as inconsistent with the relevant pricing guideline.⁹⁹

We note the concerns summarised above and, although we do not agree with all of these, have decided against proceeding with this option at this point. As such we have not formed a view on whether the guidelines would permit this or a similar proposal to be implemented.

We recognise that the proposal to de-rate would result in a substantial change in the nature of the current HVDC locational signal with North Island generation preferred, USI generation given second locational preference, and a signal against LSI generation. While this does not necessarily create a problem we do think that further consideration of the issues raised by submitters is required before this option is taken further.

⁹⁶ ENA, Submission on Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets, 28 October 2014, paragraph 15.

⁹⁷ Genesis Energy, Support for proportional changes to fix problems with current transmission cost allocation, 22 December 2014, page 6.

⁹⁸ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, page 3.

⁹⁹ Powerco, Re: Transpower TPM operational review: second consultation paper, 19 December 2014, page 2.

8. LINE MAINTENANCE RATES

We propose to alter the derivation of the \$/km allocator (for allocating maintenance costs to connection lines) to the average of the cost per km from each year for the last 4 years. Currently the \$/km allocator is derived by taking four years of costs and dividing by the current (as at June end) length of connection lines.

We do not consider that a phasing in period is warranted and propose that this change be implemented for the pricing year beginning 1 April 2016.

8.1. PROBLEM DEFINITION

Line maintenance charges are intended to recover costs incurred by Transpower to maintain connection lines for connection customers. The TPM Guidelines requires that *the definition of deep connection must avoid subsidisation of interconnection assets to the extent possible*.

Line maintenance charges are diverging from costs

The transfer by Transpower of connection assets to connection customers coupled with the derivation of this charge under the TPM (the four-year averaged maintenance costs) results in the revenue recovered through this charge exceeding Transpower's actual line maintenance costs.

Because Transpower operates to a revenue cap¹⁰⁰ the net effect is that these costs shift from interconnection charge to connection charges reducing the cost reflectivity of both charges.

Although Transpower's annual pole maintenance costs are reducing¹⁰¹, the current derivation of the \$/km allocator means there is a time lag before that cost reduction is reflected in charges. Table 8 shows how maintenance recovery rates per km of pole and 'other' lines have changed between 2011/12 and 2015/16 as the length of connection line asset recorded on our register has reduced through asset transfer.¹⁰²

Figure 8 Change in maintenance recovery rate from 2012/13 to 2015/16

Pricing year	2012/13	2013/14	2014/15	2015/16
Pole lines rate (\$/km)	\$4,128	\$5,593	\$6,200	\$8,387
Pole lines (km)	894	725	645	408
Other lines rate (\$/km)	-	-	\$5,959	\$7,269
Other lines (km)	-	-	679	484

Table 8 shows that the length of *pole* and *other* lines have reduced significantly while the maintenance rate for each line type has increased significantly. Our analysis indicates that this

¹⁰⁰ Transpower's revenue allowance takes account of cost reductions arising from completed and planned asset transfers.

¹⁰¹ Ibid

¹⁰² https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/year-specific-data-2013-14.pdf

results the allocation of \$2.4¹⁰³m in interconnection charge to connection charges, reducing the cost reflectivity of both charges.

Although the amount in question is relatively small (less than .5% of Transpower's revenues) the divergence of cost and charge is unintended. It also disproportionately impacts smaller customers (with sub 220kV connections) and those in rural areas (longer connection line lengths) for these charges make up a larger proportion of transmission charges.

If left unaddressed the current provisions could distort customer behaviour including consumption decisions at the margin and investment decisions by connection customers. For example, it may artificially incentivise connection customers to acquire assets included in Transpower's asset transfer programme.

Transpower's asset transfer programme

Transpower has a programme to transfer low voltage 'sub-transmission' assets to connection customers where we agree the customer would be better placed to own and operate those assets. We operate the asset transfer programme in accordance with the following principles:

1. Transfers must not limit our ability to develop the backbone grid.
2. Transfers must have long-term benefits to electricity consumers:
 - o lower cost for EDB to develop, operate and maintain assets
 - o reduce geographic voltage spread for Transpower
 - o avoided capital expenditure for Transpower
 - o single line, low-voltage switchboard or supply transformer (case-by-case basis)

The asset transfer programme is facilitated under regulations set by the Commerce Commission under Part 4 of the Commerce Act 1986. We have separately provided information to the Authority on this programme.

Submissions generally agreed that this was an issue.

Submissions generally agreed that the impact of asset transfers on pole maintenance charges was an issue we should look at addressing.

MEUG, for example, expressed the view that "There does appear to be an inequitable share of maintenance costs between ongoing connection customers using Transpower owned connection assets and those that have purchased connection assets from Transpower."¹⁰⁴

Powerco also noted "When the TPM was developed it was not envisaged that connection assets would be divested to the extent that they actually have been in recent years. As a consequence of the high rate of actual connection asset divestment, the four-year averaging of maintenance costs, which was intended to smooth out irregularities, has led to maintenance cost recovery being spread across a smaller number and value of assets, resulting in a higher recovery rate."¹⁰⁵

8.2. OPTIONS WE CONSIDERED

We have considered options for ensuring line maintenance rates remain cost-reflective regardless of changes in the population of these assets whether due to asset transfers or other factors.

¹⁰³ Relative to the proposed derivation of the line maintenance rate

¹⁰⁴ MEUG, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, response to Question 17.

¹⁰⁵ Powerco, Transpower TPM Operational Review: Initial Consultation, 8 August 2014, page 3.

8.2.1. GUIDANCE FROM THE AUTHORITY'S CONNECTION CHARGE WORKING PAPER AND SUBMISSIONS

We are mindful of the Authority's view "that, ideally connection charges allocated to connection customers at a connection location should be Transpower's actual costs in relation to providing, maintaining, and operating the connection assets at that location".¹⁰⁶

The extent to which actual costs can be allocated to the assets to which they relate depends on the extent to which costs are directly attributable to specific assets. As the Authority has noted "accurate allocation of operating expense to individual assets may be difficult to achieve where costs are common across multiple assets and where the increase in administration costs could make this inefficient".¹⁰⁷

The Authority has also acknowledged that the cost allocators we apply "appear to be reasonable allocators in that allocation differs in a way that may reflect operating costs, i.e. size of assets, quantity of assets, or level of use".¹⁰⁸ Consistent with this, we note the following submissions in response to the Connection Charges Working Paper:

- ENA has commented that "It is not apparent that there is a marked efficiency benefit to a different allocation of operating costs ...".¹⁰⁹
- PwC has noted, on behalf of 21 EDBs, that "The costs allocation rules applied in the current TPM ... appear appropriate for allocating operating costs particularly given these costs are either shared or directly attributed to connection assets".¹¹⁰
- Powerco has commented that "It may be possible to identify the expenditure on particularly lines more precisely, at an administrative cost, but that would be likely to result in maintenance charges for particularly assets that varied cyclically, with the variations providing no particular utility to customers".¹¹¹
- Vector has commented that "The complexity and system costs involved in [allocating operating expenditure costs to individual assets rather than cost allocators] are likely to be substantial. We are also not convinced that the benefits would be noticeable".¹¹²

While we agree with these views and, subject to the issues we have identified with line maintenance rates, improve efficiency by applying greater allocation of actual (directly attributable) costs to specific assets. The Authority requested specific views from submitters on the viability of charging operating expenses according to actual costs,¹¹³ but we are not aware of any feedback that would provide useful guidance as to how we should allocate costs differently.

¹⁰⁶ Electricity Authority, Working Paper, Transmission Pricing Methodology: Connection charges, 6 May 2014, paragraph 8.2.

¹⁰⁷ Electricity Authority, Working Paper, Transmission Pricing Methodology: Connection charges, 6 May 2014, paragraph 10.5.

¹⁰⁸ Electricity Authority, Working Paper, Transmission Pricing Methodology: Connection charges, 6 May 2014, paragraph 8.6.

¹⁰⁹ ENA, Submission on Transmission Pricing Methodology: Connection Charges, 24 June 2014, paragraph 27.

¹¹⁰ PwC, Submission to the Electricity Authority on Transmission Pricing Methodology: Connection charges, 24 June 2014, paragraph 37.

¹¹¹ Powerco, Re: Transmission Pricing Methodology, Connection charges, 24 June 2014, page 4.

¹¹² Vector, TPM working paper: connection charges, 24 June 2015, paragraph 15.

¹¹³ Electricity Authority, Working Paper, Transmission Pricing Methodology: Connection charges, 6 May 2014, paragraph 8.9.

8.2.2. OPTIONS FOR IMPROVING COST REFLECTIVITY

In the initial consultation paper we proposed to consider a shorter averaging period, or an approach based on the average km of connection lines over previous years. We noted a shorter average period would reduce the potential problem but would not eliminate it all together. There was general support for either of these options in submissions.

The table below shows these two options for allocating pole maintenance costs (equally applicable to 'other' lines). Option 1 is the average of \$/km in each year for the last 4 years and option 2 is calculated based on the total cost during the last 4 years divided by the sum of the yearly line lengths.

Table 3 Line maintenance cost allocation options

	2015			2014			2013		
	\$	km	\$/km	\$	km	\$/km	\$	km	\$/km
Pole Year One Cost	1315745	408	3,221	3047508	646	4,720	4322620	725	5,962
Pole Year Two Cost	3047508	646	4,720	4322620	725	5,962	5015326	894	5,609
Pole Year Three Cost	4322620	725	5,962	5015326	894	5,609	3625073	894	4,054
Pole Year Four Cost	5015326	894	5,609	3625073	894	4,054	3255601	894	3,641
Option 1	4,878.57			5,086.81			4,817.18		
Option 2	5,125.76			5,068.80			4,760.38		
Actual Charge	8,387.74			6,199.48			5,592.63		

Of the two options, Unison did not support the option of a shorter averaging period “as this could lead to fluctuation in prices”. Unison was of the view that an approach based on the average rate (\$/km) “is a more reasonable method with fewer anomalies as it excludes the effect of change in asset base (through divestment) and retains a relatively smooth charging pattern”.¹¹⁴ In the second consultation paper we noted that we agreed with Unison’s assessment of \$/km versus reducing the number of years the charges are smoothed over.

There was support for the \$/km option in response to both the Initial and second consultation papers from Carter Holt Harvey, Contact Energy, ENA, Mighty River Power, Orion, Powerco, and Unison.

Meridian considered that Transpower should continue to investigate averaging periods for maintenance costs.¹¹⁵ Meridian considered that “The real issue is the combination of a 4-year averaging and Transpower’s divestment decisions is impacting on an arbitrary rate” and they support “an adaptive TPM”.¹¹⁶

WEL also suggested “an alternative but still simple solution would be to adjust the average maintenance cost base in proportion to the assets sold i.e. keep a four year average (to reduce volatility) but adjust the scale of maintenance in each of the historical periods in proportion to the quality of sales sold in the most recent period”.¹¹⁷

¹¹⁴ Unison, Transpower’s TPM Operational review: Initial Consultation, 6 August 2014, response to Question 18.

¹¹⁵ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, page 5.

¹¹⁶ Meridian, Transpower TPM operational review: second consultation paper, 19 December 2014, response to Question 22.

¹¹⁷ WEL, Transpower’s TPM Operational review: Initial Consultation, 7 August 2014, page 3.

8.3. WHY WE ARE PROPOSING USING A FOUR YEAR AVERAGE OF LINE LENGTH

The proposal to use a four year average of line length will provide a better (more cost reflective) proxy for line maintenance costs. It will support the statutory objective (section 32(1)(c)) by eliminating the divergence between Transpower’s actual costs and line maintenance charges that has been caused by the transfer of connection assets to connection customers. The effect of the change in derivation method would be to:

- ensure pole maintenance charges do shift costs from interconnection charges to connection charges (and reduce the price shock predicated for some connection customers if the change is not made) as intended by the TPM Guidelines¹¹⁸
- promote efficient operation by ensuring charges remain cost reflective to the extent practicable, including:
 - reducing the risk of distorted and inefficient investment decision making by connected parties including to inefficiently acquire Transpower assets
 - reducing administrative costs associated with customer queries and investigations (for Transpower and customers) and price forecasting (for Transpower)
 - reducing the risk of inefficient curtailment in energy consumption and network utilisation by end use consumers
 - enhance price stability

We note that, although the revenue recovered through this charge represents only a relatively small (approximately 1%) proportion of Transpower’s revenues the divergence of cost unintended. It also disproportionately impacts only a subset of smaller customers (those with sub 220kV connections) and those in rural areas (with longer connection line lengths).

¹¹⁸ In its submission to our TPM operational review consultation Powerco noted “When the TPM was developed it was not envisaged that connection assets would be divested to the extent that they actually have been in recent years. As a consequence of the high rate of actual connection asset divestment, the four-year averaging of maintenance costs, which was intended to smooth out irregularities, has led to maintenance cost recovery being spread across a smaller number and value of assets, resulting in a higher recovery rate.”

9. REVERSE FLOWS (DUE TO PARALLELING)

We propose to introduce a specific provision which creates an obligation on Transpower – following Customer notification and the correct identification of a reverse flow situation under a GXP tie - to adjust AMD, AMI, RCPD and SIMI quantities to neutralise the impact of the reverse flow.

We do not consider that a phasing in period is warranted and propose that this change be implemented as soon as the Code is amended.

9.1. PROBLEM DEFINITION

No new evidence or analysis was provided in submissions, so we are largely relying on the analysis in the second consultation paper.¹¹⁹ The only new evidence we provide is on the materiality of the issue.

An issue arises where there is a through-feed via an EDB's distribution network in parallel with the transmission network. This can occur, including during RCPD peak periods on Vector's network since the commissioning of NAaN. Vector has sought arrangements for adjusting RCPD values in the event inflows occur at either Penrose or Hobson Street during a RCPD period such that the operation of the GXP ties will have no impact on Vector's transmission charges.

Paralleling also occurs elsewhere on the grid, temporarily, during switching.

The TPM requires AMD, AMI and RCPD to be calculated for each (single) connection location. There is no specific provision that caters for a situation where a customer's assets are simultaneously connected to the grid at more than one location.

This means a standard calculation of AMD, AMI and RCPD would produce the following result in situations where electricity has flowed out of the grid, into an EDB's network, and then back into the grid at another connection location:

- the "offtake" would include a quantity of electricity that flowed back into the grid from the EDB's assets and was not used by the EDB as genuine offtake
- the "injection" would reflect electricity that had merely flowed through the EDB's assets and was not a genuine injection from the EDB's assets into the grid.

The consequence of this is that the EDB would pay higher interconnection charges than that based on consumption on its network during peak periods, and would be over-charged relative to other EDBs. This would be allocatively inefficient signalling consumption should be lower in that network area relative to other networks.

We acknowledge this issue may not be material.

Vector has filed three EOC applications in the last six months; one in September, one in October and the other in December.

The September application did not qualify for an EOC because the meter aggregation did not result in an injection. The trading period (TP 29 on 21 September 2014) at which injections occurred had offtakes which were, in total, greater than the electricity injected, thus the trading period in question was an offtake rather than an injection (injections and offtakes could happen in a trading

¹¹⁹ Transpower, 2014/15 TPM Operational Review: second Consultation Paper, 13 November 2014, section 8.2.

period by the capacity factors are calculated based on net flow which is driven by the length of offtake/injection during a 30 minute period and the magnitude of offtakes/injections).

The injection that occurred from TP 10 on 5 October to TP 15 on 6 October at HOB was caused by the fire at Penrose. Transpower approved Vector's EOC application for this event as the net flows during these periods are injections. It seems that, if not for the fire, injections (as far as the calculation of the TPM capacity factors is concerned) caused by GXP paralleling may not have occurred.

There are four GXP ties on the Vector network:

- ALB110-WRD33 (normal operation): power should flow into Vector's network from ALB110 and WRD33 GXPs under all conditions;
- HOB110-PEN110 (normal operation): during the CBD upgrade works, under certain steady state configuration and outage/contingency combinations reverse flow at HOB110 GXP can occur. After the CBD upgrades, summer loads with outage/contingency combinations may cause significant reverse flow at HOB110 GXP. For winter loads, steady state configurations may cause reverse flow at HOB110 GXP, and could be exacerbated by certain outage/contingency combinations;
- HOB110-ROS110 (back-up operation): to be used post CBD upgrades as back-up ties for outages and contingency management. Power should flow into Vector's network under all conditions; and
- PEN110-RSO110 (back-up operation): to be used post CBD upgrades as back-up ties for outages.

The Vector December EOC application relates to injections that occurred on 2 – 3 December and is currently under review.

We also note we are planning (not committed yet) to have new 220 kV and 66 kV lines at Orion's network which would be paralleled and are likely to result in reverse flows like Vector's.

There was general acknowledgement paralleling is an issue and, where it arises, it results in over-charging. Vector, as the party most affected, expressed agreement that "...the potential problems with paralleling on distribution networks are of significant concern to warrant a change to the TPM to account for such arrangements ... It is clear the TPM does not account for situations where through-feed via a distribution network occurs. This results in over-charging."¹²⁰

There was also acknowledgement of a problem from other parties. Carter Holt Harvey and MEUG, for example, both acknowledged "The current TPM would appear to over-charge GXP connected parties in such cases".¹²¹ Northpower described the situation as a "quirk" and noted "Currently with Vector being subject to N=12, this would a very real issue for Vector and could (presumably) also distort the RCPD demand periods for other grid-connection customers in the UNI."¹²²

9.2. OPTIONS WE CONSIDERED

A data adjustment to undo the effect of this distortion can be made under the TPM's EOC provision. While this is a pragmatic interim solution, the situation will arise on an ongoing basis.

¹²⁰ Vector, Transpower TPM Operational Review: Initial Consultation, 6 August 2014, response to Question 19 and 20.

¹²¹ Carter Holt Harvey, Initial consultation feedback on possible TPM operational changes, 8 August 2014, response to Question 19.

¹²² Northpower, untitled, 8 August 2014, responses to questions 20 and 21.

We remain of the view it would be preferable for the TPM to include a specific provision that deals with the calculation of capacity factors under a GXP tie¹²³ (rather than continuing to treat this as an exceptional situation). Such a provision would require Transpower – when requested to do so by our customers – to adjust AMD, AMI, RCPD and SIMI quantities to neutralise the impact of the reverse flow.. It would also provide certainty to customers that their charges would be adjusted where paralleling occurs (by removing the discretion available to Transpower under the EOC provisions).

There was strong support for this option in response to both the Initial and second consultation papers: Contact Energy, ENA, Genesis Energy, Meridian ("so long as the circumstances are genuine"), Mighty River Power, Norske Skog, NorthPower, Powerco, Unison, Vector and WEL.

WEL and Norske Skog's support was subject to materiality (see above). Similarly Genesis Energy also expressed the view that "Transpower's proposal to address the issue of charging when there is "throughfeed via a distribution network" seems logical on the face of it. However, we note that Transpower will need to show that the added complexity would be of net benefit and is required in practice."¹²⁴

In response to these proportionality concerns, we can confirm addressing the paralleling issue through amendment to the TPM would be straightforward and would not give rise to any cost or complexity. There would be reduced administrative costs with parties not having to apply for an EOC whenever the paralleling issue arose.

MEUG considered "A better solution would be an exacerbators-pay or beneficiaries-pay approach provided the benefits exceeded the costs. MEUG suggests this problem may be solved by the EA review exploring those and other approaches and therefore it should be considered in the concurrent cl.12.86 review by the EA".¹²⁵

We note the options MEUG proposed are outside of the scope of our Operational Review and are unlikely to be warranted by the paralleling issue.

¹²³ For further information on GXP ties see: http://www.systemoperator.co.nz/sites/default/files/bulk-upload/documents/AOI-07-110_Paralleling-GXPs.pdf

¹²⁴ Genesis Energy, Submission on TPM Operational Review: Initial Consultation, 8 August 2014, page 3.

¹²⁵ MEUG, Initial consultation on possible TPM operational changes, 8 August 2014, responses to questions 19 and 21.

10. FUTURE OPERATIONAL REVIEWS OF THE TPM

We do not plan to undertake any further TPM Operational Reviews prior to the Authority completing its own TPM review.

We have previously noted “we would expect to periodically review the TPM regardless of what the TPM was”.¹²⁶

The majority of submitters that commented agreed periodic TPM reviews would make the TPM more durable: Contact Energy, Genesis Energy, Mighty River Power, Pacific Aluminium, Orion, Trustpower, and Unison. Trustpower, for example, has expressed the view “Operational reviews of this nature will enhance the durability of the TPM Guidelines”.¹²⁷

Mighty River Power expressed the view: “... Transpower should commit to a periodic review of N as the outlook for transmission investment changes. Transpower's demand response programme should not necessarily be the first port of call ...”¹²⁸ and “Consideration could be given to ... context specific triggers such as evidence of structural change in demand (e.g. major thermal generation or load exit) that would then reset the timeframe for the periodic review”.¹²⁹ We acknowledge the possibility of events given rise it being desirable for reviews to occur at different times as well. Where circumstances were such that we considered an ad hoc Operational Review was potentially desirable we would consult with our customers, other interested parties and the Authority on whether we should undertake such a review.

¹²⁶ Transpower, Transmission pricing methodology: problem definition working paper, 28 October 2014, page 10.

¹²⁷ Trustpower, TRUSTPOWER SUBMISSION: TRANSPOWER TPM OPERATIONAL REVIEW, 5 August 2014, paragraph 1.1.2a.

¹²⁸ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, response to Question 5.

¹²⁹ Mighty River Power, Transpower Transmission Pricing Methodology Operational Review: second Consultation, 19 December 2014, response to Question 30.

APPENDIX 1: INDUSTRY ENGAGEMENT

We received submissions on the Initial and second consultation papers from 22 parties:

Table 4 Submitters

Distributors	Generators/Retailers	Consumers / Other
Counties Power ²	Contact Energy	Carter Holt Harvey ¹
ENA ²	Genesis Energy	MEUG
Unison	Mighty River Power	Norske Skog Tasman ¹
Network Waitaki ¹	Meridan Energy	Pacific Aluminium
Northpower ¹	Pioneer Generation	NZ Steel ¹
Orion ²	TrustPower	PanPac ¹
Powerco		WPI
Vector		
WELL ¹		

1 = Submitted on initial consultation paper only. 2 = Submitted on second consultation paper only.

In addition, the TPM Operational Workshops that we held in Auckland, Christchurch and Wellington were attended (physically or by phone) by the following parties.

Table 5 Workshop participants

Distributors	Generators/Retailers	Consumers / Other
Alpine Energy	Contact Energy	Appleby Engineering
Counties Power	Genesis Energy	Concept Consulting
Mainpower	Meridan Energy	Electricity Authority
Marlborough Lines	Mighty River Power	MEUG
Northpower	Pioneer Generation	NZ Steel
Orion	Trustpower	NZAS
The Lines Company		NZIER
ThinkDelta		P2P Energy (Winstone Pulp)
Vector		Sapere
Waipa Networks		

As well as formal submissions and the workshops we had bilateral conversations with a number of customers and interested parties.

APPENDIX 2: SCIENTIA REPORT

Please refer to: *Scientia consulting, Market impact analysis of HVDC MWh and diluted HAMI charge, January 2015*

Related modelling instructions and input files to permit replication of Scientia's modelling are also provided.