Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets

Working paper

16 September 2014

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1 Executive summary

Introduction

1.1 The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover the costs of operating, maintaining, upgrading and extending the transmission grid.

1.2 Following submissions on the October 2012 issues paper and the May 2013 TPM conference, and submissions on working papers released to date, the Authority decided to re-examine its TPM problem definition. The Authority considers that the problem definition outlined in the October 2012 issues paper could have been set out more clearly. As a consequence it has decided to prepare this working paper.

1.3 This problem definition working paper builds on the problem definition provided in the October 2012 issues paper. It identifies and, where possible, quantifies problems with the current TPM, as assessed against the Authority's statutory objective.

1.4 This paper does not consider potential problems relating to connection charges, the recovery of the costs of network reactive support (NRS), or the treatment of loss and constraint excess (LCE) income except to the extent that they relate to problems with the interconnection and HVDC charges and prudent discount policy (PDP). The Authority considers that problems relating to these elements of the TPM are addressed in other working papers.[1] All problems that the Authority has identified with the current TPM will be addressed in the second issues paper.

1.5 The second issues paper will include an updated problem definition.

The problem definition must relate to the Authority's statutory objective

1.6 The Authority has the statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long term benefit of consumers.

1.7 The Authority may only approve a TPM that is consistent with the Authority's statutory objective. The TPM is part of the Electricity Industry Participation Code 2010 (Code), and the Code can include only those provisions that are consistent with the Authority's statutory objective, and which are necessary or desirable to promote the matters specified in section 32(1) of the Electricity Industry Act 2010 (Act).

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[1] Or, in the case of NRS, through the October 2012 issues paper and further publications on the Authority's website (in particular, see the discussion under the heading "Static Reactive Support" at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/second-issues-paper/).

1.8 Therefore, in identifying problems with the current TPM, the Authority has focused on those problems that are inconsistent with achievement of the Authority's statutory objective.

The Authority's statutory objective has been interpreted in the decision-making and economic framework

1.9 The Authority has previously considered how to interpret its statutory objective in the context of transmission pricing. Its conclusion, determined after consultation, is set out in the decision-making and economic (DME) framework paper released on 7 May 2012 (DME framework). The focus of the DME framework is overall efficiency of the electricity industry for the long-term benefit of electricity consumers.

1.10 Overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand-side management:

(a) efficient use of the grid focuses on least cost production, and charging customers the efficient marginal costs of production

(b) efficient investment focuses on the lowest cost development of the industry over time.

1.11 Accordingly, this working paper considers problems with the current TPM, as assessed against the Authority's statutory objective as interpreted in the DME framework.

Problems with the TPM

1.12 This paper focuses on three principal problems with the current TPM in relation to the Authority’s statutory objective (as interpreted in the DME framework). The three problems are summarised as follows:[2]

(a) the HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution, and by load

(b) the current TPM is not durable, creating uncertainty for investors and therefore inefficient investment

(c) the HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry.

1.13 Fundamentally, these problems arise because parties pay interconnection and HVDC charges that do not adequately reflect the cost of supplying transmission services to them. Since transmission services are provided through a network, it can be difficult to attribute the costs of providing transmission services to individual consumers, other than for connecting a customer to the grid.[3] This means it can be difficult to set charges based on service levels delivered to each

[2] Note that this does not include problems that are outside the scope of this paper, such as the problems with connection charges that are discussed in the Authority’s Connection charge working paper.

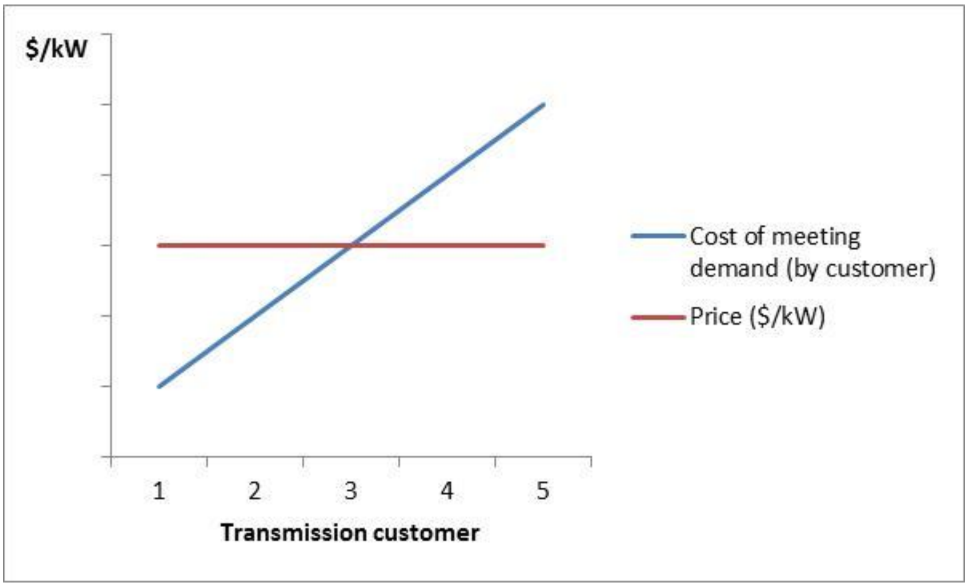
[3] For example, the interconnected nature of a transmission grid means an investment to deliver transmission services to one group of customers can, for example, improve the quality of transmission services provided to another group of customers. Further, the quality of services provided by the investment can be affected by the subsequent connection of another customer or the reconfiguration of the grid. Note though that, while it can be difficult to attribute the costs of services in aggregate provided to a customer, it may be feasible to attribute additional costs to additional service delivered to customers, such as attempted by PJM’s ‘But For’ approach.

customer. As a result, a free-riding problem is created whereby some parties are provided with higher levels of service but are not required to pay more. This creates incentives on those free-riding parties to seek higher levels of service. Further, given the emphasis on reliable supply under instruments such as the grid reliability standards, this is likely to lead to transmission investments earlier than is efficient and inefficient decisions around the nature, location, and timing of investments.

1.14 Although this paper provides examples of these effects it is not necessary to rely on them as it is well-established in economics that parties tend to respond to the incentives they face in order to maximise their own self-interest.

1.15 Figure 1 below illustrates the crux of the problem. This diagram illustrates that under the current TPM some customers pay considerably more than the cost of transmission services to them while others pay considerably less.

Figure 1 Price does not reflect cost of supply of transmission services



1.16 The over-charging and under-charging results from the way that interconnection and HVDC charges are set. In particular:

(a) *Interconnection charges*. The interconnection charge applies the same rate of charge across the grid.[4] This rate is based on the non-HVDC and non-connection costs that Transpower is able to recover under Commerce Commission price-quality regulation rather than the costs of supplying transmission services to each customer. The interconnection charge only applies to load, which means the cost of supplying interconnection services to generators is fully cross-subsidised by load.

[4] See clause 29 of the TPM in Schedule 12.4 of the Code. However the number of peaks (n) used to calculate interconnection charges differs across the four transmission pricing regions. In particular, 12 peaks are used to calculate interconnection charges for the Upper North Island (UNI) and Upper South Island (USI) regions, while 100 peaks are used for the Lower North Island (LNI) and Lower South Island (LSI) regions. See clause 3 of the TPM in Schedule 12.4 of the Code.

(b) *HVDC charges*. The HVDC charge only applies to South Island (SI) generators. As a consequence, the cost of supplying HVDC services to all other transmission users is cross-subsidised by SI generators.

1.17 As transmission charges do not broadly reflect the cost of supplying transmission services to each Transpower customer, this promotes inefficient investment, inefficient use of the grid, and it undermines the durability of the TPM. These three principal problems can be summarised as follows:

(a) *Inefficient investment*. Where the price a party faces for transmission services is less than the cost of supply they have an incentive to consume more transmission services than is efficient. Given the emphasis on reliable supply rather than efficient operation under instruments such as the grid reliability standards (GRS) and the grid investment test (GIT), this is likely to lead to transmission investments earlier than is efficient and inefficient decisions around the nature and location of investments. In turn, this is likely to result in inefficient investment in generation, transmission alternatives, distribution, and by consumers.

(b) *Poor durability*. A lack of durability of the TPM as parties are likely to have incentives to continue to lobby and push for a change to the TPM to avoid continuing to cross-subsidise the costs of meeting other parties' demand for transmission services. This can adversely impact perceptions around regulatory certainly and ultimately affect investor confidence.

(c) *Inefficient use of the grid*. This occurs because parties facing charges that are higher than the cost of supplying them with transmission services will seek to inefficiently avoid use of the grid, while those facing charges less than the cost of supplying them with transmission services will seek to use the grid more than is efficient. In turn, this is likely to drive inefficient investment (inefficient decisions around the location, nature, and timing of investments in transmission assets, transmission alternatives, generation assets, distribution, and by load).

1.18 As a consequence, the Authority considers that the current TPM fails to promote the Authority's statutory objective of promoting efficient operation of, competition in, and reliable supply by the electricity industry for the long-term benefit of consumers.

1.19 The Authority sought to quantify these problems to the extent possible. This is summarised in Table 1.

Table 1: Quantitative assessment of the problems

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
General	The TPM fails to promote efficient investment in transmission, generation, distribution and by load.	The scale of the inefficiency has not been estimated. However the Authority notes that the potential for inefficiencies is large. For example, the value of a five-year deferral of an investment with a cost of $200M, that would otherwise have been required in 5 years, is $43.5M PV (using an 8% real discount rate).
	The TPM is not durable.	Estimated to be at least $36.5M PV.
Interconnection	RCPD allocation over-signals the need for load shedding at peak times.	The economic effect of short-term demand response to RCPD signals in the LNI and LSI is estimated to be a net cost in the range from $1M PV to $58M PV. The net economic effect of short-term demand response to RCPD signals in the UNI and USI is estimated to be somewhere between a $38M PV cost and a $12M PV benefit. These estimates assume there is not an unforeseen need for major transmission investment.
	The interconnection charge may over-signal the need for overall reductions in consumption.	Inefficiency estimated to be between $3M and $40M PV.[5]

[5] This inefficiency is distinct from the inefficiency immediately above ("RCPD allocation over-signals the need for load shedding at peak times"). The two issues are distinct - the issue above is about short-term demand response to RCPD signals in potential coincident peak periods, while the issue on this row refers to parties that do not respond to RCPD signals in the short term, but may instead reduce their overall level of consumption in response to transmission charges. Therefore, the two effects are additive.

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
Interconnection	The interconnection charge may over-signal the cost of increasing Tiwai smelter production in summer.	Inefficiency estimated to be in between \$4M and \$32M PV.[6]
	The interconnection charge may over-signal the value of embedded generation.	The interconnection charge affects the investment in and operation of embedded generation in two ways: • through setting the rate of payments in relation to the avoided cost of transmission (ACOT) • through providing an incentive on load to invest in and operate embedded generation. The Authority has yet to complete its consideration of submissions on the ACOT working paper so has yet to reach a final position on the efficiency or otherwise of the ACOT arrangements. The matter will be addressed in the second issues paper.
	The interconnection charge may over-signal the value of generation to direct-connect consumers.	Likely to be immaterial, relative to other efficiency effects discussed in this paper.

6 This inefficiency is additional to the inefficiency immediately above ("interconnection charge may over-signal the need for reductions in consumption"). The two issues are distinct - the issue above includes the possibility that Tiwai might reduce year-round consumption as a result of the RCPD charge, and the issue on this row is that Tiwai might increase summer consumption if there was no RCPD charge. Therefore, the two effects are additive.

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
HVDC	The HAMI allocation may incentivise SI generators to withhold existing capacity.	The inefficiency is estimated to be in the order of $12M PV. This estimate assumes that generators will continue to withhold SI hydro capacity. In practice, the trading conduct provision may discourage this.
	The HAMI allocation may discourage upgrades to SI generation capacity.	Probably small.
	HVDC charge may discourage investment in SI grid-connected generation.	May be in the order of $25M PV – *if* there is a need for substantial new generation investment over the next few years.
	The HVDC charge may bring forward the need for upper SI transmission investment.	The deferral benefit foregone as a result of the HVDC charge is estimated to be between $2M and $6M PV – unless there is unforeseen need for major transmission investment.
PDP	The existing PDP may not efficiently disincentivise generators or loads from bypassing the grid.	The Authority will assess the need for and nature of the PDP in the second issues paper in the context of options it considers.

Cross check

1.20 While the Authority has assessed the problem definition against the statutory objective by using the DME framework, the Authority will also provide a cross-check in the second issues paper that considers identified problems directly against each limb of the statutory objective.

Conclusion and next steps

1.21 The Authority has reconsidered its problem definition after reviewing the feedback in relation to identification of problems with the TPM from its various consultations.[7] Note that the Authority has not yet completed consideration of the submissions on working papers received to date. The Authority will fully consider submissions on all the working papers once the working paper process is complete and prior to drafting the second issues paper. However, having

[7] Namely, submissions and cross-submissions on the first issues paper, verbal and written feedback from the TPM conference, informal discussions with parties, and working papers.

revisited the problem definition through the development of this working paper, the Authority's view continues to be that there are sufficient problems with current TPM charges to justify continuing the TPM review.

1.22 The Authority will use feedback from submissions on this working paper to further inform its problem definition analysis and to prepare the second issues paper.

1.23 The quantitative and qualitative assessment of the problems with the existing TPM will be a key input into the cost-benefit analysis that underpins the second issues paper.[8]

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8 While the quantitative and qualitative assessment of the problems will be key inputs into the cost-benefit analysis, the structure of the cost-benefit analysis will be principally informed by the cost-benefit analysis working paper and the feedback from submitters on that working paper.

Contents

Tables

Figures

Glossary of abbreviations and terms

AC	Alternating current
ACOT	Avoided cost of transmission
AMD	Anytime maximum demand
AMP	Asset management plan
CBA	Cost-benefit analysis
Code	Electricity Industry Participation Code 2010
DG	Distributed generation
DME	Decision-making and economic framework
EA	Electricity Authority
ENA	Electricity Networks Association
EOC	Exceptional operating circumstances
FTR	Financial transmission rights
GFC	Global Financial Crisis
GIT	Grid investment test
GRS	Grid Reliability Standards
HAMI	Historical anytime maximum injection
HILP	High impact low probability
HVAC	High Voltage Alternative Current
HVDC	High voltage direct current
IC	Interconnection
IPP	Individual Price Path
LCE	Loss and constraints excess
LNI	Lower NI
LRMC	Long-run marginal cost
LSI	Lower South Island
MAR	Maximum allowable revenue
NAaN	North Auckland and Northland
NI	North Island
NIGU	NI Grid upgrade
NRS	Network reactive support
PDP	Prudent discount policy

RCPD	Regional coincident peak demand
SI	South Island
SOO	Statement of Opportunities
SRMC	Short-run marginal cost
SSF	System Security Forecast
TPAG	Transmission Pricing Advisory Group
TPM	Transmission pricing methodology
UNI	Upper NI
USI	Upper South Island

2 Introduction

Background to process

2.1 The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of operating, maintaining, upgrading and extending the transmission grid.

2.2 The Authority considers that the current TPM can be improved so as to better meet the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Working papers

2.3 The Authority decided to advance the process of reviewing the TPM by developing a second TPM issues paper (second issues paper) for consultation following consideration of submissions on the Authority's October 2012 paper "TPM: Issues and Proposal" (October 2012 issues paper) and information provided at the TPM conference held in Wellington on 29–31 May 2013. This will include revised draft guidelines to be followed by Transpower in developing a new TPM (as referred to in clause 12.89 of the Code).

2.4 Prior to developing a second issues paper, the Authority is further considering and consulting on key aspects of a revised TPM proposal through a series of working papers, which will provide key inputs into the second issues paper.

Background to this working paper

2.5 Following consideration of submissions on the October 2012 issues paper, the responses of parties to the Authority's questions at the May 2013 TPM conference, and submissions on problems identified in the Authority's working papers to date, the Authority decided to prepare a problem definition working paper to clarify its views on problems with existing TPM charges, and to seek further feedback. The Authority considers that submitter feedback on a problem definition working paper could be used to better inform the Authority's problem definition in the second issues paper.

Purpose and scope of this working paper

2.6 This working paper discusses and, where possible, quantifies, problems with the current TPM. It does so by assessing the current TPM against the Authority's statutory objective (as interpreted in the DME framework).

2.7 This working paper builds on the problem definition provided in the October 2012 issues paper.

2.8 This paper does not consider the problem definition for connection charges, the recovery of the costs of network reactive support (NRS), or for the treatment of loss and constraints excess (LCE) income except to the extent that they relate to problems with the interconnection and HVDC charges and PDP. The Authority considers problems relating to these elements of the TPM are addressed in other working papers.[9] All problems the Authority has identified with the current TPM (in the October 2012 issues paper or in the other working papers listed below) will be addressed in the second TPM issues paper.

Other working papers

2.9 Other working papers the Authority has completed or will complete include:

(a) Cost benefit analysis (CBA) – This paper outlined a revised approach that the Authority intends to apply to the cost-benefit analysis of a revised TPM proposal that will be included in the second issues paper. (Submissions closed)

(b) Definition of sunk costs – This paper examined the implications for transmission pricing if assets were sunk. (Submissions closed)

(c) Avoided cost of transmission (ACOT) – This paper considered the efficiency implications of any changes to the TPM in relation to ACOT payments. (Submissions closed)

(d) Use of loss and constraint excess (LCE) to offset transmission charges – This paper explored submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals. (Submissions closed)

(e) Beneficiaries-pay approach – This paper examined options for applying a beneficiaries-pay charge. (Submissions closed)

(f) Connection charges – This paper examined whether the pool charging approach for transmission connection assets is efficient and whether there is potential for connection assets to be inefficiently classified as interconnection assets. (Submissions closed)

(g) LRMC charge working paper – This paper examines whether the use of long-run marginal cost (LRMC)-based transmission charges to recover the costs of HVDC and interconnection assets would better promote the Authority's statutory objective than maintaining the status quo. (Released on 29 July 2014 with submissions due on 23 September 2014)

(h) Approach to residual charge – This paper will consider the most efficient approach to residual charges, including whether it may be efficient to levy any residual charge on the basis of congestion rather than load during peak demand periods. (To be released)

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9 Or in the case of NRS, through the October 2012 issues paper and further publications on the Authority's website. For more information on NRS, refer to the Authority's website: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/second-issues-paper/

2.10 In submissions on the working papers, a number of submitters suggested that a problem definition working paper should be prepared and released prior to other working papers discussing key issues with the TPM, including options for amending it. The Authority acknowledges those submissions, but considers that it is appropriate to publish a problem definition working paper at this stage in the process. This is because the Authority considers that the problem definition in the October 2012 issues paper remains valid so it is appropriate to identify options to address the problems identified through working papers. However, as identified through submissions, there is a need to better articulate the problem definition in the second issues paper. The Authority has therefore developed this working paper to inform the development of the problem definition in the second issues paper.

Decisions on the TPM

2.11 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Electricity Industry Participation Code 2010 (Code) be consistent with the Authority's statutory objective.

2.12 The TPM is part of the Code, so any provision or amendment to the TPM must be consistent with the Authority's statutory objective.

2.13 In order to assist the Authority to make decisions about the TPM consistent with its statutory objective, the Authority developed the DME framework.[10] The DME framework set out the Authority's interpretation of its statutory objective in the context of transmission pricing. It also set out the Authority's views on how the Authority would decide between the options for allocating the costs of transmission services.

2.14 In developing the second issues paper, the Authority will continue to be guided in its decisions by its DME framework.

2.15 The Authority's Consultation Charter[11] sets out guidelines relating to the processes for amending the Code and the Code amendment principles (CAPs) that the Authority will adhere to when considering Code amendments.

2.16 The second issues paper will set out the Authority's problem definition (refined or amended as necessary following considerations of submissions on this working paper) and will identify options to address those problems. These options will be assessed against the DME framework and the CAPs. In addition, as a check, the options will be assessed directly against the Authority's statutory objective.

[10] Electricity Authority, May 2012, Decision-making and economic framework for transmission pricing methodology: decisions and reasons, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

[11] Available from http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/.

2.17 The second issues paper will also include a cost-benefit analysis (CBA), consistent with the requirement to prepare a regulatory statement under section 39 of the Act.

2.18 The Authority has noted submitter comments on the October 2012 issues paper and the CBA working paper, that the Authority's problem definition and CBA were poorly aligned. The Authority agrees that it is important that the problem definition and cost-benefit analysis are well aligned. Accordingly, the Authority will develop its detailed framework for CBA of TPM proposals consistent with the problem definition presented in the second issues paper.

3 Submissions on this working paper

3.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the TPM.

3.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with *Working Paper – Transmission pricing methodology: Problem definition* in the subject line.

3.3 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

3.4 Submissions should be received by 28 October 2014. Please note that late submissions are unlikely to be considered.

3.5 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

3.6 Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

4 Approach to defining problems with the TPM

4.1 This section of the working paper discusses the Authority's approach to defining problems with the current TPM.

Process for developing problem definition

4.2 As part of the October 2012 issues paper, the Authority set out a problem definition.[12] Following submissions on that paper, the TPM conference and submissions on working papers to date, the Authority came to the view that the TPM problem definition could be further clarified and refined in advance of the second issues paper.

4.3 This working paper assesses problems with the current TPM against the Authority's statutory objective as interpreted through the DME framework (see paragraphs 4.9 – 4.11 below).

4.4 The Authority will use feedback from submissions on this working paper to further inform its problem definition analysis and its findings will be published in the Authority's second issues paper.

4.5 The second issues paper will include an updated problem definition and will identify options to address those problems. The second issues paper will assess problems with the current TPM against the Authority's statutory objective as interpreted through the DME framework. The Authority's quantitative assessment of the problems with the existing TPM will be a key input into the CBA that underpins the second issues paper.

The problem definition must relate to the Authority's statutory objective

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

4.7 The Authority may only approve a TPM that is consistent with the Authority's statutory objective. The TPM is part of the Code, and the Code can include only those provisions that are consistent with the Authority's statutory objective and which are necessary or desirable to promote the matters specified in section 32(1) of the Act.

4.8 Therefore, the Authority has focused on those problems that are inconsistent with achievement of the Authority's statutory objective.

The Authority's statutory objective has been interpreted in the decision-making and economic framework

4.9 The Authority has already considered how to interpret the statutory objective in the context of transmission pricing. Its conclusion, set out in the DME framework paper, is that the Authority should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that competition is an important tool to encourage efficient outcomes and that measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

[12] Paragraphs 4.0 to 4.6, October 2012 issues paper.

4.10 Overall efficiency refers to both efficient use of the grid and efficient investment in the electricity industry – the grid, generation and demand-side management.

4.11 Accordingly, this working paper considers problems with the current TPM, as measured against the Authority's statutory objective as interpreted through the DME framework.

Problem definition not restricted to problems that arise from material change in circumstances threshold

4.12 Clause 12.86 of the Code states that the Authority may review an approved TPM if it considers that there has been a material change in circumstances.

4.13 The Authority considers that the requirement to meet the material change in circumstances threshold for a TPM review does not restrict the Authority to identifying problems that arise only as a result of the identified material change in circumstances. That is because any amendment to the Code must be consistent with the Authority's statutory objective. If the changes proposed to address issues arising from the material change in circumstances do not provide the optimal solution in terms of consistency with the statutory objective, then the Authority is required to consider a broader, optimal solution.

5 The Authority’s objectives for the TPM

5.1 As set out in the previous section, the Authority’s decision-making in relation to the TPM will focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers.

5.2 This reflects the Authority's statutory objective. It also recognises that efficiency and reliability in the electricity industry involves facilitating:

(a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time and are in the right place. These investments can be in the transmission grid, generation (including distributed generation), distribution networks or on the demand-side

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management. This means providing incentives so that the day to day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.

5.3 Efficient investment in the electricity industry primarily relates to dynamic efficiency, while efficient operation primarily relates to static efficiency. The Authority noted in its *Interpretation of the Authority’s statutory objective* that, because the Authority’s statutory objective requires it to promote the *long-term* benefit of consumers: *“… the Authority considers that its primary focus is to promote dynamic efficiency in the electricity industry, which includes:*

(a) taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in the electricity industry, by both suppliers and consumers

(b) *taking into account the durability of the industry and regulatory arrangements in the face of high impact, low probability events.”*[13]

5.4 As some submitters pointed out,[14] determining the design of an efficient transmission charge is likely to require a trade-off between static and dynamic efficiency. The above quotation from the *Interpretation* suggests that where such a trade-off is required, preference should be given to promotion of dynamic efficiency.

Question 1: Do you agree that, in relation to decisions around transmission pricing, the Authority should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers? Why or why not?

13 Paragraph A11, *Interpretation of the Authority’s statutory objective,* 14 February 2011.

14 e.g. Vector: “Fundamentally, if the Authority is going to consider making changes to the TPM, Vector believes it should make an explicit judgement as to whether TPM should focus on recovery of sunk costs in a way that minimises distortions to nodal pricing and transmission network use (static efficiency) or on long-run (dynamically efficient) signalling of future transmission capacity costs e.g. locational-pricing.” Vector submission on October 2012 issues paper, page 3.

Considerations for efficient transmission charges

5.5 The DME framework consultation paper[15] noted that transmission services are essentially transport services, in that transmission services involve the transportation of a product (electricity) from its place of production (where the electricity is generated) to consumers directly connected to the grid and distributors that transport the product to the end consumers who want to use it. The paper suggested it could therefore be instructive for developing a robust TPM to consider the pricing of transport services in a transport market.

5.6 The DME framework consultation paper noted that, provided the transport market is workably competitive, transport businesses are forced to set their prices for a service at the level that just covers the additional cost of adding another unit of transport – the short run marginal cost (SRMC). For example, in the case of a trucking business, the SRMC would include the costs of additional drivers and fuel. The paper noted that when there is workable competition this pricing structure promotes three sources of efficiency:

(a) **Productive efficiency**: the efficient production of transport services or otherwise new entrants with lower costs will enter or threaten to enter the market at lower prices and take away business from other producers if their costs remain higher

(b) **Allocative efficiency**: the efficient use of the transport service, as producers and consumers will transport their goods only when the benefits of transporting exceed the costs of transport

(c) **Dynamic efficiency**: efficient investment decisions as:

(i) consumers and producers face price signals that ensure they take into account the cost of transport when deciding where to locate their next plant and/or expand existing plant

(ii) transport businesses face price signals that ensure they only add capacity to their business when consumers are willing to pay for it.

5.7 It is important to note that dynamically efficient pricing provides signals about both contraction and expansion of services. Where lack of demand means the transport service is not able to recover its SRMC this provides a signal to reduce the service, e.g. reduce the number of flights to a particular destination. Similarly, where excess demand means the firm could recover more than SRMC it has a signal to expand the service, e.g. increase the number of flights to a destination.

5.8 Transmission is not, in general, subject to workable competition as it is a natural monopoly.[16] Further, transmission is subject to significant economies of scale, which means the SRMC of supply is below the average cost of supply. This

[15] Refer section 4.1, *Decision-making and economic framework for transmission pricing review: Consultation paper,* 26 January 2012, for the discussion on the characteristics of prices for transport services in workably competitive transport markets.

[16] This is certainly the case with respect to the core grid. It may, however, be feasible for more than one provider to compete to provide a connection to the core grid – e.g. the party seeking the connection to the grid and the grid owner. Further, it may be economic to bypass such connections or the grid itself although this may not be efficient.

means charges based on SRMC would significantly under-recover the total cost of providing transmission services.

5.9 In the absence of economies of scale, it might be possible to rely on nodal pricing. This is because nodal pricing provides the (approximately) correct signals about the SRMC of transmission through its pricing of losses and constraints on the grid. This means that nodal pricing promotes both:

(a) productive efficiency, by providing signals for the efficient operation of the transmission network

(b) allocative efficiency, by providing signals for the efficient use of the transmission network, as generators and consumers will only use the transmission network when the benefits of the transmission of power across the grid exceeds the costs.

5.10 The significant economies of scale associated with transmission mean that an option for recovering the costs of transmission favoured by early electricity market designs – the use of loss and constraint excess (LCE)[17] – does not provide sufficient revenue as this only covers the SRMC of transmission.

5.11 As some submitters pointed out[18], charges based on the long run marginal cost (LRMC) of transmission would provide efficient price signals about the cost of transmission investment. The LRMC of transmission can be defined as "the capital and operating costs that would be incurred to increase transmission capacity (as opposed to throughput) by one unit"[19]. In keeping with the example of the trucking business discussed above, the LRMC would incorporate the additional investment in trucks and assets required to meet increased demand. The operating expenses incurred through operating the additional trucks and other assets would also fall within the definition of LRMC. Charges based on LRMC would promote dynamic efficiency since such charges would ensure that:

(a) consumers and producers face price signals that ensure they take into account the cost of transmission investment when making their own investment decisions. This includes:

(i) expansion

(ii) location

(iii) innovation

(b) the transmission provider would face a price signal to only add capacity when consumers of transmission services are willing to pay for it.

What is efficient pricing?

5.12 As noted above, there is a trade-off between static and dynamic efficiency in relation to determining the most efficient TPM charging regime. The Authority notes that its statutory objective, which requires it to focus on the long term

[17] In particular, it was suggested that LCE could be either retained by the transmission provider or sold as FTRs.

[18] e.g. Vector Submission on the October 2012 issues paper.

[19] Definition from NZIER, *New Zealand Transmission Pricing Project A Review of the NERA Report to the Electricity Industry Steering Group, Report to MEUG,* 1 September 2009, page 3.

benefit of consumers, requires it to focus on the longer term, and thus provides for a preference for efficient investment, and dynamic efficiency.

5.13 For investment efficiency, in a broad sense, the transmission system should be augmented[20] when the increased (marginal) benefits from an investment exceeds the costs of that investment (marginal cost). Accordingly, an efficient price, in an investment sense, might be defined as the price that adequately signals the cost of efficient investments.

5.14 For efficient operation, the price should be set in a manner that minimises deadweight loss or, ideally, eliminates the deadweight loss entirely. Under a price where there is no deadweight loss there is no inefficient avoidance of the transmission system in response to the price. This promotes efficient capacity utilisation. Were the Authority to focus on minimising deadweight loss, Ramsey pricing (that is, charging consumers at rates (in percentile terms) that are inversely proportional to the absolute value of their elasticity[21]) might be considered an appropriate arrangement. However, as noted above, in determining the appropriate price it is necessary to consider the trade-off between dynamic and static efficiency, or efficient investment and efficient operation.

5.15 The Authority set out in its Interpretation of the Authority's statutory objective that it believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in minimising total costs.[22] As a consequence, the Authority is also interested in promoting the durability and stability of the TPM as it believes this will promote competition, reliability and efficiency for the long-term benefit of electricity consumers.

5.16 The Authority considers that a durable charge is a charge that is as objective as possible, can adapt to changing circumstances, avoid perverse outcomes, and promote certainty. If the TPM is not durable, this can lead to intensive lobbying and disputes, requests for ad-hoc interventions, and a need for further TPM reviews. These outcomes are both costly and time consuming, and would adversely impact on both regulatory certainty and investor confidence. The recent request for a TPM exemption by Transpower in relation to the North Auckland and Northland (NAaN) project and Transpower's operational review of the TPM add credence to the existence of a durability problem with the existing TPM.

5.17 In conclusion, the above reasoning suggests that the Authority should assess transmission charges in terms of whether they are efficient and, in particular, whether charges:

(a) facilitate efficient investment, and thus promote dynamic efficiency

(b) are durable, and thus promotes efficiency, generally

(c) facilitate efficient operation, and thus promote allocative and productive efficiency.

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20 Notwithstanding Transpower's additional requirement to invest to satisfy its reliability obligations provided for by the grid reliability standards (GRS) in Schedule 12.2 of the Code.

21 Another version of Ramsey pricing would be to spread charges across *both* consumers and generators – again, in inverse proportion to elasticity.

22 Paragraph A46, Appendix A, *Interpretation of the Authority's statutory objective.*

Question 2: Do you agree with the Authority's view on what constitutes an efficient charge? What role do you consider durability plays in determining efficient charges? Please explain your answers.

6 The current TPM

6.1 The current TPM has applied since 1 April 2008, but is similar to the methodology adopted by Transpower in the late 1990s. The TPM is used to recover Transpower's costs of providing the transmission grid, including the costs of capital, maintenance, operating, and overheads.

6.2 The TPM is not used to recover all of Transpower's costs. Notable exceptions are costs associated with:

(a) providing system operator services. These are paid for under a contract between the Authority and Transpower

(b) investment contracts between Transpower and connected parties allowed for under clauses 12.70, 12.71 and 12.95 of the Code

(c) a number of notional embedding contracts and fixed-term connection contracts agreed under the TPM that applied prior to 2008

(d) Transpower's activities that are not regulated under Part 4 of the Commerce Act 1986 (i.e. not included in Transpower's Maximum Allowable Revenue (MAR)), such as its role as the manager of financial transmission rights (FTRs).

6.3 The key components of the TPM are:

(a) connection charges

(b) HVDC charges

(c) interconnection charges.

6.4 The prudent discount policy is another component of the TPM and is summarised below.

Connection charges

6.5 Connection charges recover the costs of alternating current (AC) assets connecting a distributor, grid-connected major user and/or generator to the grid. The definition of connection assets is technically complicated[23] but a practical interpretation is that a connection asset is one on which there cannot be loop-flows (apart from flows on a "small regional loop"). Voltage support equipment that is used for voltage support purposes and has not been installed at the customer's request is excluded from the definition of connection assets.

6.6 Note that given that a problem definition for connection charges is out of the scope of this working paper, further technical detail on existing connection charges has been intentionally omitted. However, this high level definition of connection charges is provided as this context is important when considering whether there are problems with other transmission charges.

[23] Connection assets are defined in clause 6, Schedule 12.4 of the Code. Connection charges are addressed in clauses 8-26, Schedule 12.4 of the Code.

HVDC charges

6.7 HVDC charges recover the costs of the HVDC link between the North and South Islands.[24] The charges are paid by customers at each SI generation connection location.[25] This is where any generating unit or station located in the SI is either directly connected to the grid or is connected to a local network that is connected (directly or indirectly) to the grid. For the charges to apply in relation to SI generation there must also have been an injection of electricity into the grid at any time during the capacity measurement period for the previous five pricing years.

6.8 The annual HVDC charge is calculated for each HVDC customer at each SI generation connection location by multiplying Transpower's required HVDC revenue by the ratio of the customer's historical any time maximum injection (HAMI) at the location to the sum of all HVDC customers' HAMI over all SI generation connection locations. The HVDC charge is set on a $/kW basis.

6.9 HAMI for a transmission customer at a SI generation connection location is the higher of:

(a) the average of the 12 highest injections at that location during the capacity measurement period[26] for the relevant pricing year, or

(b) the average of the 12 highest injections at that connection location during any of the four immediately preceding pricing years.[27]

6.10 The HVDC rate for the 2013/14 March year was $50.82/kW and HVDC charges were forecast to total $162.5M.

Interconnection charges

6.11 An interconnection asset is any grid asset that is not a connection asset, or an HVDC asset. The purpose of the interconnection charge is to recover the remainder of Transpower's revenue for providing AC services that is not recovered via connection charges.[28] Interconnection charges are paid to Transpower by offtake customers only; in other words, by lines companies and direct grid-connected major users.

6.12 The annual interconnection charge is calculated for each offtake customer at a connection location by multiplying the interconnection rate by the sum of the customer's average regional coincident peak demands (RCPD) at the connection location during the capacity measurement period.

6.13 The interconnection rate is the same for all offtake customers and all connection locations in all regions.[29] It is therefore sometimes described as a "postage stamp" charge because the rate of the charge for interconnection services is the same across the grid, regardless of location. That is, the interconnection charge

[24] HVDC charges are addressed in clauses 31-33, Schedule 12.4 of the Code.

[25] Note that generators below10MW are below the threshold for dispatch by the System Operator.

[26] The capacity measurement period means for any pricing year, the 12 month period starting 1 September and ending 31 August inclusive, immediately before the commencement of the pricing year (clause 3, Schedule 12.4 of the Code).

[27] Clause 3, definitions, Schedule 12.4 of the Code.

[28] Interconnection charges are addressed in clauses 27-30, Schedule 12.4 of the Code.

[29] See clause 29 of Schedule 12.4 of the Code.

is just like national postage where the price for posting a letter is the same regardless of where in the country the letter has been posted to. The interconnection rate is calculated by dividing Transpower's required interconnection revenue by the sum of the average RCPDs for each customer at each connection location for all customers at all connection locations for all regions during the capacity measurement period. It is set on a $/kW basis.

6.14 The RCPD for a customer at a connection location is the customer's offtake at that location during a regional peak demand period.[30] A regional peak demand period means in the UNI and USI a half hour in which any of the 12 highest regional demands occur during the capacity measurement period for the pricing year.[31] In relation to the LNI and LSI it means a half hour in which any of the 100 highest regional demands occur.

6.15 The interconnection rate for the 2013/14 March year was $99.44/kW and interconnection charges were forecast to total $574.2M.

6.16 Note that, while the interconnection rate is the same for all offtake customers across the grid, the different number of peaks used to calculate RCPD in different regions means the implicit cost of consuming electricity during a potential coincident peak period is higher in the upper North and upper South Islands than in the lower North and lower South Islands. This is because each coincident peak period in the UNI and USI contributes 1/12th of a customer's interconnection charge in these regions, whereas in the LNI and LSI each coincident peak contributes 1/100th of a customer's charge. This means there is a strong incentive to avoid coincident peak periods in the UNI and USI.

Prudent discounts

6.17 The current TPM also includes a PDP.[32] The purpose of the PDP is to help ensure that the TPM does not provide incentives for the uneconomic bypass of existing grid assets. As such, it is an element of the overall methodology for charging for transmission assets. The PDP allows charges for an offtake party that would otherwise not connect to the grid, or would disconnect, to be discounted so as to leave them in the same economic position as they would be if they avoided use of the grid by investing in an alternative project.

6.18 There are stringent requirements to be met before a prudent discount can be granted by Transpower because costs of agreed prudent discounts are recovered from other transmission customers in accordance with the TPM. Prudent discounts are not available where the alternative project would involve new investment in generation.

6.19 Only three prudent discount agreements have been made since the current TPM was implemented in 2008.[33] Prior to 2008, a number of notional embedding contracts, the precursor to prudent discount agreements, were signed and several of these are still operative.

30 Clause 3, definitions, Schedule 12.4 of the Code.

31 Pricing year means the period from April 1 to March 31, in respect of which Transpower calculates its prices (clause 3, Schedule 12.4 of the Code).

32 The PDP is defined in clauses 36-42, Schedule 12.4 of the Code.

33 This statement was accurate as at 22 August 2014. See: https://www.transpower.co.nz/about-us/industry-information/revenue-and-pricing.

7 The October 2012 issues paper and submitter feedback

The Authority identified several problems with the current TPM

7.1 In the October 2012 issues paper, the Authority identified several problems with the current charging arrangements for HVDC, connection, interconnection and reactive support assets. The Authority considered that the current TPM charging arrangements caused inefficient investment and inefficient operation within the electricity industry. The Authority sought feedback about the nature and materiality of problems with the current TPM, asking a series of questions about the efficiency of outcomes resulting from the connection charge, HVDC charge, interconnection charge, the recovery of network reactive support costs, and the prudent discount policy and inefficient disconnection.

Feedback on the October 2012 issues paper and feedback received at the TPM conference

7.2 The following is a selection of concerns raised by parties in relation to the TPM problem definition:[34]

(a) The Authority did not adequately identify problems with the TPM. Some submitters considered that the Authority's problem definition lacked supporting analysis. For example, submitters did not consider that a customer being charged an amount that did not reflect the customer's private benefit represents a problem, and there was a need to better describe the consequences of there being a material difference between private benefit and the HVDC charge.[35]

(b) The Authority did not establish that the scale of the problem(s) was sufficiently material as to require significant changes to the existing TPM. For example, submitters considered that the Authority needed to demonstrate that the problem is sufficiently large to justify change and should undertake further analysis of the 'benefits' of the HVDC link, which was the basis for the current cost allocation regime.[36] Similarly, some submitters agreed that HAMI led to inefficient outcomes, but were not convinced that the effect was sufficiently material to warrant changes to HVDC charges.[37] Other parties submitted that HVDC charges were the only problem that required fixing[38], and that the Transmission Pricing Advisory Group's (TPAG) analysis had already sufficiently identified a problem.[39]

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[34] Note that connection charges, treatment of LCE, and reactive support-related charges are outside the scope of this working paper.

[35] Norske Skog submission p.9; Vector submission p.40-41. (submissions on the October 2012 issues paper).

[36] CHH submission p.2; MEUG submission p.8; Smart Power submission pp 4-5; Transpower submission Appendix A p.2. (submissions on the October 2012 issues paper).

[37] For example, CHH submission p 6; DEUN submission p.10; MRP Appendix A p.2; Pacific Aluminium p.14. (submissions on the October 2012 issues paper).

[38] For example, Genesis cross-submission on October 2012 issues paper, p.2.

[39] For example, MRP submission on October 2012 issues paper, p.28.

(c) The Authority needed to show a clear link between the problem definition and the solution being proposed.[40]

(d) The Authority's problem definition needed to be robust and should represent a material change in circumstances to justify amending the TPM.[41]

The Authority's response to submissions relating to the problem definition

7.3 A selection of submitter concerns with the problem definition, as set out in the October 2012 issues paper, and the Authority's responses are summarised in Table 2 below.

7.4 The Authority acknowledges that there have been a number of submissions on working papers to date in relation to the Authority's problem definition. The decision to develop this working paper is in response to some of those submissions.

7.5 Note that a discussion of submissions on the Authority's working papers will be provided in the second issues paper.

Table 2: Submitter comments and Authority response

Application of the DME framework in guiding the problem definition

Submitter comment	Explanation and action
The decision-making and economic framework is unfit for purpose.	• The decision-making and economic framework should be retained as: - it is consistent with the Authority's statutory objective and the Code amendment principles - it was developed after widespread consultation and incorporation of feedback from stakeholders - it provides clarity and structure to the development of a TPM that provides for investment efficiency and operational efficiency, which the Authority has decided should be the main objectives for the TPM based on its interpretation of the statutory objective. • However, for completeness, the Authority will also consider the current TPM and any proposed TPM against all limbs of the Authority's statutory objective.

40 NZ Wind Energy Association, p.59, TPM conference transcript.

41 Appendix A, MRP submission to the October 2012 issues paper. Para 1, page 1.

Submitter comment	Explanation and action
The decision-making and economic framework provides for pricing approaches whereas principles, such as that used by PJM, would provide a useful, supplementary guide.[42]	• The Authority will assess the current TPM against the decision-making and economic framework. Namely, it will assess the current TPM against its efficient investment and efficient operation objectives. The economic framework component of the decision-making and economic framework will be used to assess any TPM proposals that will be set out in the second issues paper. As stated above, the Authority will also assess the TPM against each limb of its statutory objective in the second issues paper. • The Authority considers that including specific criteria for evaluation or broad pricing principles is likely to complicate the Authority's assessment. In particular, detailed criteria or broad pricing principles are likely to lead to multiple interpretations of the criteria and/or principles. Note that, in 2011, the Authority removed the pricing principles formerly specified in the Code for transmission because it considered that they were complex, unwieldy, and created a demonstrable regulatory failure.

Material change in circumstances (as it relates to problem definition)

Submitter comment	Explanation and action
The Authority's problem definition should represent a material change in circumstances to justify making changes to the TPM.[43]	• The Authority does not consider that the material change in circumstances threshold restricts the Authority in identifying problems, or proposing solutions. This is because the Code must be consistent with the Authority's statutory objective. Accordingly, if the changes proposed to address issues arising from the material change of circumstances do

[42] Page 29, MRP submission, TPM conference transcript.

[43] Para 1, page 1, Appendix A, MRP submission to the October 2012 issues paper.

Submitter comment	Explanation and action
	not provide the optimal solution in terms of consistency with the statutory objective, then the Authority is required to consider a broader, optimal solution.

Interconnection

Submitter comment	Explanation and action
The Authority's analysis has not established that there are inefficiencies around current RCPD charges.[44]	• The Authority disagrees. This problem definition working paper provides further analysis on the efficiency of current RCPD charges, including a quantitative assessment of the problems identified. • The Authority notes that Transpower has instigated an operational review of the TPM, under which it is considering changes to address suggestions that there are inefficiencies with the current RCPD charge.
RCPD isn't linked to capacity so it could be driving inefficiencies but these are difficult to quantify.[45]	• The Authority agrees that, given the current number of peaks on which RCPD charges are based are not linked to capacity and the extent of impending transmission investment, this may drive inefficiencies in at least some of the RCPD regions. The Authority has attempted to measure the size of the potential problem using both qualitative and quantitative analysis. •
More work is needed to understand whether there are issues outside of transmission pricing that might be driving distributor response.[46]	• This paper further examines the response of distributors to RCPD charges. The Authority notes that Commerce Commission price-quality regulated distributors are unlikely to have strong incentives to respond directly to the charges as they have a regulatory right to fully pass through transmission charges. Community controlled distributors, however, face some incentives to respond to the charges, partly because they are not

[44] MRP, conference transcript.

[45] MRP, conference transcript, p.53.

[46] MRP, conference transcript, p.53.

Submitter comment	Explanation and action
	covered by those regulations.
For interconnection charges there needs to be a balance between static and dynamic efficiency.[47]	• The Authority agrees that a trade-off between static and dynamic efficiency is likely to be required. The Authority considers that dynamic efficiency is more important than static efficiency.
It is not necessary to efficiently recover sunk costs in a way that minimises distortion in the use of the grid as that is a static efficiency argument when dynamic efficiency is more important.[48]	• The Authority agrees that it should have a preference for dynamic efficiency over static efficiency since the Authority's statutory objective requires the Authority to consider the "long term" benefit of consumers. • The treatment of sunk costs is considered in the sunk costs working paper and the Authority has yet to complete its analysis of submissions in response to that paper.
A market-based, exacerbators-pay or beneficiares-pay approach to allocating the costs of the HVAC interconnection assets would result in an allocation significantly different to the current inefficient smearing of these costs across consumers only.[49]	• The Authority considers that charges that seek to reflect costs are likely to best promote efficient outcomes. A smeared charge is unlikely to do this as it does not reflect the actual cost of supply for different consumers across the grid. A smeared charge is likely to create inefficient incentives in relation to investment and operation, and can adversely affect the durability of charges.

HVDC

Submitter comment	Explanation and action
The dispatch and investment inefficiencies associated with HVDC link have been robustly identified via bottom up modelling approaches from successive reviews and the Authority's own analysis. The Authority has a	• The Authority has reassessed dispatch and investment inefficiencies associated with the HVDC link using actual examples where possible.

[47] Meridian Energy, conference transcript.

[48] Pacific Aluminium, conference transcript.

[49] Pacific Aluminium cross-submission, p.6.

Submitter comment	Explanation and action
clear mandate to resolve the cost allocation of the HVDC.[50]	
TPAG did not properly specify a problem with the HVDC locational signals, i.e. they did not establish that the HVDC charges exceeded LRMC and therefore did not establish that the signal to invest in the North or South Island was too strongly biased against South Island locations.[51] Current HVDC charges send a locational signal that efficiently discourages South Island generation. Even if it is accepted that there is an efficiency cost of $30M NPV in current HAMI charges, given the amount, and the volume of money that is being recovered for that efficiency loss, it is actually a very efficient tax. If the Government had a form of tax that had such a small efficiency cost, it would probably move to increase the use of that tax, not remove it.[52]	• The Authority has reconsidered its problem definition for HVDC charges for this working paper.
It is not clear why the Authority has largely replicated the TPAG analysis concerning the HVDC costs and alleged inefficiencies. The NZIER analysis raised serious questions with the TPAG work, namely around the simplified assumptions the model uses, and the validity of its conclusions concerning the alleged inefficiencies of the HVDC charge.[53]	• The TPAG work largely relied on the GEM analysis. This problem definition working paper uses an alternative approach for calculating the inefficiency of the existing HVDC charges.

50 MRP, Supplementary responses to the TPM conference questions.

51 Vector cross-submission on the October 2012 issues paper, p.7.

52 Vector, conference transcript.

53 Pacific Aluminium cross-submission on the October 2012 issues paper, p.6.

Submitter comment	Explanation and action
HVDC costs have doubled since pole 3 has come into effect which will add 20% more to costs to a wind farm in the South Island as compared to a like-for-like wind farm in the NI. This will likely push all new South Island generation out of merit compared with NI generation.[54]	• The Authority has reconsidered its problem definition in relation to HVDC charges causing inefficient investment in SI generation.
Companies like Meridian put standing instructions in place to make sure that power stations aren't operated above a certain limit.[55] The current HAMI charge sends the wrong generation signal and the wrong net benefit signal and extra generation would be made available to the market if charges were based on megawatt hour rather than megawatt capacity.[56]	• The Authority has reconsidered its problem definition in relation to the question of whether HVDC charges incentivise inefficient operation of SI generators.

Prudent discount policy (PDP)

Submitter comment	Explanation and action
Many industries need the security of supply that goes along with connection to the grid. Accordingly, it is unlikely that an industrial would disconnect because they would lose the benefit of that connection and that security of supply.[57]	• The Authority considers that an industrial consumer will make choices according to the economics of the options before it. In particular, if the benefit of disconnection exceeded the costs of the supply security provided by the connection to the grid it is likely that industrial consumers will disconnect. Whether this occurs in practise will depend on the level of transmission charges, the cost and quality of supply of alternatives to transmission, and the requirements of the industrial consumer.
When the old notional embedding	• Noted. The demand for PDPs will also

54 Meridian, conference transcript.

55 Meridian, conference transcript.

56 Contact, conference transcript.

57 Contact, conference transcript.

Submitter comment	Explanation and action
agreements and other variants of a prudent discount agreement come to the end they are being replaced by prudent discounts.[58]	depend on the level of transmission charges and the cost of alternatives to transmission.
There are practical achievability issues around the provision of a prudent discount for notional generation. Notional generation investments are very difficult to value, namely, the insurance value, the option value, and the technical benefits received from having some connection to the grid versus self-supply.[59]	• This working paper examines practicality considerations of PDPs in section 12.

The Authority's position

7.6 This working paper responds to the submissions received on the TPM problem definition to date by:

(a) restating the Authority's objectives for the TPM (this included identifying what behaviours or outcomes are considered to be efficient)

(b) identifying the characteristics of transmission charges that promote those objectives

(c) identifying the extent to which the existing charges promote or detract from those objectives.

7.7 The Authority will consider submissions on this working paper, as well as relevant submissions on other working papers, and then develop a refined problem definition in the second issues paper.

Question 3: Do you agree with the Authority's position on the problem definition, described above? Please explain your answer.

[58] Transpower, conference transcript.

[59] Transpower, conference transcript.

8 Main findings

8.1 This problem definition working paper focuses on problems with HVDC and interconnection charges.

8.2 The Authority has re-examined the TPM problem definition and it considers that its previous problem definition (outlined in the October 2012 issues paper) could be set out more clearly. This paper focuses on three principal problems with the current TPM in relation to the Authority's statutory objective (as interpreted in the DME framework). The three problems are:[60]

(a) the HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution and by load

(b) the current TPM is not durable, creating uncertainty for investors and therefore inefficient investment

(c) the HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry.

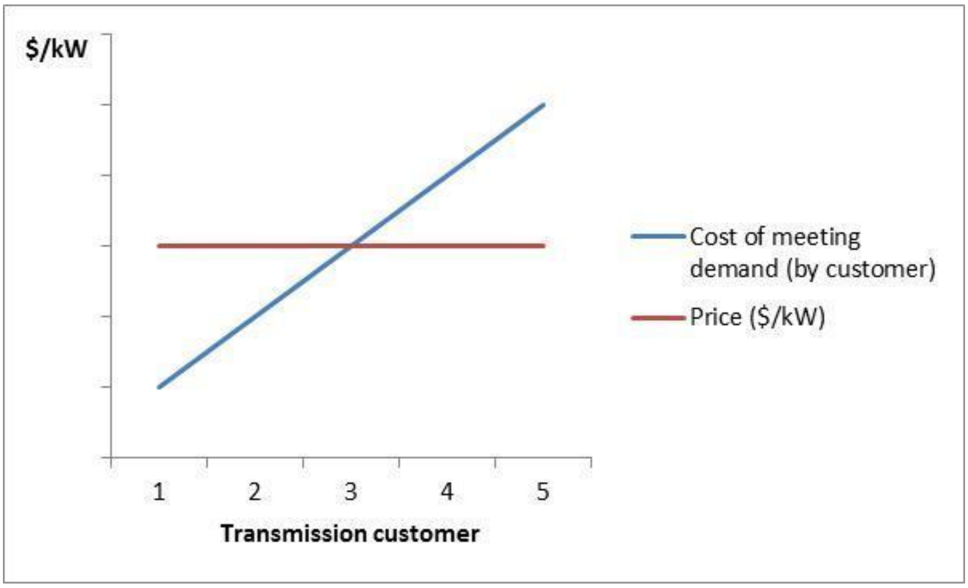
8.3 Fundamentally, these problems arise because parties pay interconnection and HVDC charges that do not adequately reflect the cost of supplying transmission services to them. Since transmission services are provided through a network, it can be difficult to attribute the costs of providing transmission services to individual consumers, other than for connecting a customer to the grid.[61] This means it can be difficult to set charges based on service levels delivered to each customer. As a result, a free-riding problem is created whereby some parties are provided with higher levels of service but are not required to pay more. This creates incentives on those free-riding parties to seek higher levels of service. Further, given the emphasis on reliable supply under instruments such as the grid reliability standards, this is likely to lead to transmission investments earlier than is efficient and inefficient decisions around the nature, location, and timing of investments.

8.4 Figure 2 below illustrates the crux of the problem. This diagram illustrates that under the current TPM some customers pay considerably more than the cost of transmission services to them while others pay considerably less.

[60] Note that this does not include problems that are outside the scope of this paper, such as the problems with connection charges that are discussed in the Authority's Connection charge working paper.

[61] For example, the interconnected nature of a transmission grid means an investment to deliver transmission services to one group of customers can, for example, improve the quality of transmission services provided to another group of customers. Further, the quality of services provided by the investment can be affected by the subsequent connection of another customer or the reconfiguration of the grid. Note though that, while it can be difficult to attribute the costs of services in aggregate provided to a customer, it may be feasible to attribute additional costs to additional service delivered to customers, such as attempted by PJM's 'But For' approach.

Figure 2: Price does not reflect cost of supply of transmission services



8.5 The over-charging and under-charging results from the fact that transmission costs are effectively socialised across the grid. In particular:

(a) *Interconnection charges*. The interconnection charge applies the same rate of charge across the grid.[62] This rate is based on the non-HVDC and non-connection costs that Transpower is able to recover under Commerce Commission price-quality regulation rather than the costs of supplying transmission services to each customer. The interconnection charge only applies to load, which means the cost of supplying interconnection services to generators is fully cross-subsidised by load.

(b) *HVDC charges*. The HVDC charge only applies to SI generators. As a consequence, the cost of supplying HVDC services to all other transmission users is cross-subsidised by SI generators.

8.6 As transmission charges do not broadly reflect the cost of supplying transmission services to each Transpower customer, this promotes inefficient investment, inefficient use of the grid and it undermines the durability of the TPM. These three principal problems can be summarised as follows:

(a) *Inefficient investment.* Where the price a party faces for transmission services is less (more) than the cost of meeting their demand they have an incentive to consume more (less) transmission services than is efficient. Given the emphasis on reliable supply rather than efficient operation under instruments such as the grid reliability standards (e.g. reliability investments do not require a positive expected net electricity market benefit in order to be approved[63]), this is likely to lead to transmission investments earlier than

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[62] Although there is a form of differential charging based on the differing number of peaks (n) applied across each of the four regions used in calculating interconnection charges. The regions are: Upper North Island (UNI), Upper South Island (USI), Lower North Island (LNI), and Lower South Island (LSI).

[63] In particular, the Commerce Commission Capital Expenditure Input Methodology states:

> "For a proposed investment to satisfy the investment test it must have a positive expected net electricity market benefit unless it is designed to meet an investment need generated by a deterministic requirement of

is efficient and inefficient decisions around the nature, location and timing of investments. In turn, this is likely to result in inefficient investment in generation, transmission alternatives, distribution, and by consumers.

While the Commerce Commission Part 4 regime seeks to provide incentives for more efficient transmission investment by Transpower, it is the price for transmission services that determines parties' demand for transmission services, which in turn determines the transmission investment required. Transmission charges therefore affect the nature and timing of transmission investments coming before the Commerce Commission for approval. Because current transmission charges do not adequately reflect the cost of providing transmission services to different customers, the timing and nature of transmission investment proposals coming before the Commerce Commission is unlikely to be efficient.

(b) *Poor durability.* A lack of durability of the TPM as parties are likely to have incentives to continue to lobby and push for a change to the TPM[64] to avoid continuing to cross-subsidise the costs of meeting other parties' demand for transmission services. The inefficiency impacts of poor durability are far reaching. For example, uncertainty around the TPM can have a consequential impact on investment decisions and dynamic efficiency. The significant resources that are used in lobbying activities, such as exemption requests and applications for changes to the TPM, hinders productive efficiency.

(c) *Inefficient use of the grid.* This occurs because parties facing charges that are higher than the cost of supplying them with transmission services will seek to inefficiently avoid use of the grid, while those facing charges less than the cost of supplying them with transmission services will seek to use the grid more than is efficient. In turn, this is likely to drive inefficient investment (inefficient decisions around the location, nature, and timing, of investments in transmission assets, transmission alternatives, generation assets, distribution, and by load).

8.7 As a consequence, the Authority considers that the current TPM fails to promote the Authority's statutory objective of promoting efficient operation of, competition in, and reliable supply by the electricity industry for the long-term benefit of consumers.

8.8 It is important to note here that there is no perfect TPM charge. The important matter is whether the price for transmission services sufficiently approximates the cost of meeting a customer's demand for transmission services, in order to promote efficient investment, durability of the TPM, and efficient use of the grid Where price does not approximate the cost of meeting a consumer's demand for

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the grid reliability standards." Page viii, paragraph X28, Transpower Capital Expenditure Input Methodology Final Reasons paper, 31 January 2012.

> "The investment options for an investment required to satisfy a deterministic requirement of the grid reliability standards may have a negative expected net electricity market benefits. In this case, the proposed investment must be the one with the least negative expected net electricity market benefit." Page 108, paragraph 7.3.23, *ibid.*

[64] Or seek exemptions.

transmission services, the consequence is inefficient investment in and use of the grid.

8.9 The following sections further explore the three principal problems with the TPM identified above.

9 Promotion of efficient investment

9.1 The Authority has noted from its various consultations that some parties are of the view that the determination of what is an efficient transmission investment is the role of the Commerce Commission, and that the TPM has no function to perform in promoting efficient investment decisions.

9.2 The Authority considers that there are key differences between the role of the Commerce Commission and the role of the TPM in promoting efficient investment. An examination of the Commerce Commission's role in approving Transpower's investments is provided in Appendix B. Transpower has been required to get regulatory approval before it can charge for capex since 2004. Arguments that its investments have been efficient since that time and will continue to be so appear to overlook several points:

(a) **Information asymmetry.** As has been discussed extensively in the economics literature,[65] regulators are likely to have less knowledge about the entities they regulate than the entities know about themselves, the circumstances they face and their industry. As a result of this information asymmetry, an entity requiring approval for an investment by a regulator has the ability to amplify the need for a particular investment, overstate the benefits and understate the costs, dismiss alternatives to its preferred investment, etc. To the extent these practices happen, investments can be inefficient.

(b) **Regulator incentives.** A regulator is exposed to reputational risk should it decline any transmission investment proposal. Should there subsequently be any failure in the grid that could have potentially been addressed by the proposed investment it is likely the failure will be attributed to the regulator's decision by media, public opinion and politicians. This may occur even if the proposed investment would not have prevented or mitigated the failure.

On the other hand, an increase in charges that will be financially insignificant for most consumers is very unlikely to result in criticism of the regulator, even if the investment is inefficient.

(c) **Lines company incentives.** Although the regulator may not have as in-depth an understanding as Transpower about its business, lines companies, which are levied a significant proportion of interconnection charges under the current TPM, are better placed to understand Transpower's business. Lines companies and Transpower share many of the same technologies. Lines companies are likely to be reasonably well informed about transmission engineering and related issues, the need for any particular transmission investment and the relative efficiency and feasibility of alternative transmission-type options. However, as has already been noted, lines companies under price regulation can pass on all the transmission charges levied on them to their customers.

As a result, lines companies may have little direct financial incentive to vigorously contest investment proposals by Transpower that they consider

[65] For example, Jean-Jacques Laffont, Jean Tirole, *A theory of Incentives in Procurement and Regulation*, 1993, p.295.

to be inefficient or unnecessary.[66] In fact, lines companies need to maintain a collaborative relationship with Transpower as their equipment is required to interface with Transpower's and co-operation is essential for their own safe and efficient operation. Therefore, lines companies, in some cases may have little financial incentive to challenge Transpower's investment proposals and may have an operational incentive not to create disputes with Transpower.

This appears to be reflected by line company submissions in relation to major transmission investment proposals. As shown in Appendix C (which is discussed in detail in paragraphs 9.28–9.34 below), lines companies do not appear to have submitted in opposition to any of the major transmission investments, even when there was little direct benefit to them and the consequence of these investments was a significant increase in their transmission charges.

Note that the fact that many lines companies are able to pass through transmission charges is not a sufficient reason to dispense with attempting to provide efficient price signals about investment to lines companies through transmission charges. Through their own charges, lines companies can still pass on the price signals for efficient investment incentives through to their customers.

(d) **Cost spreading and effect on consumer incentives.** A large proportion of the economic costs of interconnection assets are borne by commercial, small and medium-sized industrial and residential consumers. The charging regime spreads the costs of an interconnection investment across all New Zealand offtake customers, not just those served by the offtake nodes where the investment's benefits will accrue. This means the financial impact of each investment on virtually all businesses and households is insignificant, and too small for each individually to be concerned about. As a result the incentive for almost all individual consumers to scrutinise Transpower's investment proposals is extremely limited.

Major electricity users can, however, have a reasonably strong incentive to scrutinise Transpower's investments. Through individual action and, more often, through their industry body MEUG, they do so, as shown in Appendix C.

As noted above, the charging regime spreads the costs of an interconnection investment across all New Zealand offtake customers, not just those whose demand for transmission services has necessitated the investment. In practice, the benefits from an investment are often reasonably concentrated in an area or region. For example, Transpower's NIGU and NAaN projects largely benefit consumers in Auckland and further north.[67] The outcome is that while benefits can be reasonably concentrated the costs are spread thinly, though not perfectly evenly because of the workings of the RCPD allocator, but widely spread nevertheless. This

[66] Although the Authority understands that there may be incentive mechanisms on Boards and management to control costs, particularly in the case of community controlled distributors.

[67] For example, https://www.transpower.co.nz/projects/north-island-grid-upgrade#zoom=6&lat=-37.8388&lon=175.5&layers=TB.

means the incentive on any individual party to scrutinise an investment can be low.

(e) **Investments in the core grid.** Reliability investments required so that the core grid meets the N-1 safety net do not require a positive expected net electricity market benefit in order to be approved. This means Transpower is permitted to make economically inefficient investments under the current investment test (as it was under the previous investment test applied by the former Electricity Commission). That an investment has been approved under the existing investment test regulations does not mean it is efficient in an economic sense. Further, since Transpower is not subject to optimisation[68] and thus is not required to absorb the costs of stranded assets, there is arguably a reduced incentive on Transpower to scrutinise its own investments to ensure that it does not overbuild or, otherwise, invest inefficiently.

The role of the TPM in supporting the discovery of efficient transmission investments

9.3 The following section (paragraphs 9.6 – 9.13) focuses on the supporting role of the TPM in incentivising participants to support the discovery of the most efficient transmission solution (or non-transmission solution). Namely, the TPM can provide incentives to parties subject to transmission charges, either directly or indirectly, to promote the discovery of the most efficient investment option, and to ensure that these efficient options are proposed to the Commerce Commission (so that the Commerce Commission is provided with the opportunity to approve the most efficient option). This is because transmission charges affect the demand for transmission services, and so affect the volume, timing and scale of investment proposals coming before the Commission.

9.4 An efficient TPM will also promote the discovery of efficient non-transmission alternatives. For example, if the TPM is inefficient and transmission costs are socialised across customers, transmission customers would likely prefer transmission solutions, that they pay only a portion of, as opposed to non-transmission options (such as electricity distribution assets), whereby they are likely to have to meet the full costs of the investment. An efficient TPM will improve the parity between transmission investments and non-transmission alternatives so that only efficient transmission investments are proposed to the Commerce Commission.

9.5 Ultimately the role of the TPM in promoting efficient investment is in ensuring that prices promote efficient demand for transmission services.

Selecting efficient transmission investments (or non-transmission alternatives) is highly challenging

9.6 Transmission investments are, by nature, large and “lumpy” investments. As it is often efficient to build greater capacity than what is required to address immediate requirements, this can amplify the detrimental impact of an inefficient investment. Assessment of transmission investment options is complex. Scrutiny

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[68] This means that Transpower is permitted to earn a return on capital over assets, even where an asset becomes stranded.

of transmission investments requires specialist knowledge, which is rare in New Zealand, and access to detailed, difficult to access, and sometimes confidential, information. As discussed above, the information asymmetry problem is a well-understood problem in regulated industries, whereby the regulator inevitably knows less about the entity it regulates than the entity knows itself, and this problem is particularly acute in complex industries where information is of a technical nature.

9.7 Electricity transmission investments are often large, and the scope for inefficiencies where a suboptimal decision is made around the location, nature and timing, of transmission investments and transmission investment alternatives, is considerable. Yet identification of the most efficient alternative is not always straightforward. Engineers often have significant differences of opinion on the most efficient alternative. Further, since projects take considerable time to implement, the Commerce Commission is required to approve investments well in advance of an investment taking place. Investment decisions are often required to be made when the need for an investment remains unclear. The decision rests upon demand projections, speculation around the future location of generators and loads, possible plant closures, and prediction of potential changes to technology. Technological change can lead to shifting demand profiles. It can also lead to new and improved transmission assets or improved processes whereby the optimal solution changes.

9.8 The Authority considers that certain transmission customers[69] have specialist knowledge in regard to transmission investments (and, in fact, are practiced in developing non-transmission alternatives), have access to detailed information, and understand the uncertainties surrounding these investments. When those transmission customers are faced with the cost of Transpower investments, as long as their share of the costs are sufficiently material, it is expected that those transmission customers would provide comprehensive scrutiny on those investments. They will also be incentivised to carefully consider non-transmission alternatives.

9.9 However, since the TPM effectively socialises interconnection costs across all load customers, load customers face only a small portion of the costs of any investment, even when an investment was undertaken principally to support the requirements of a single customer. Generation customers do not face any of the costs of an interconnection investment even when the investment has been undertaken to support their requirements.

Examples

9.10 Suppose that, under a socialised charge, a customer pays only 10% of the costs of a transmission investment. This means that if, for example, the customer had a choice between a transmission investment and undertaking an investment themselves (which would mitigate the need for the transmission investment) which is twice as efficient as the transmission investment, the transmission customer would likely lobby for the transmission investment because it would pay only 10% of the costs of the transmission investment but 100% of the costs of its own investments. Neither Transpower nor the Commerce Commission may have

[69] and possibly their customers.

even heard about the alternative.[70] Depending on the relative cost difference between the transmission investment and the alternative, the more efficient alternative might only be discovered if the party for whom the transmission investment was built, faces the full cost of that investment. This example illustrates that a price signal is required that ensures that the most efficient investment proposal reaches the Commerce Commission for its consideration.

9.11 By way of another example, the consumption of electricity by New Zealand Aluminium Smelters Limited (NZAS) did not cause the North Auckland and Northland (NAaN) upgrade to be required. Nevertheless, NZAS is required to pay a relatively high portion of the costs of NAaN (about 10%) on account of its share of RCPD, and, in fact, all load customers in New Zealand are required to pay a portion of NAaN based on their share of RCPD. The effect of charging all offtake customers a share of NAaN is that the parties whose injection and offtake behaviour (and general demand) actually caused the requirement for the NAaN upgrade[71] (and benefit from NAaN) face a much smaller portion of the costs than they otherwise would have faced if they paid for the investment themselves.

9.12 The result is that the parties whose demand (or whose customers' demand) for transmission services led to the need for the investment, who may have specialist knowledge in the project, and who could be in a position to thoroughly scrutinise the investment (e.g. in the case of NAaN, the UNI distributors, who are best placed to scrutinise NAaN), will face only a "watered-down" portion of the costs. Thus, instead of scrutinising the investment to ensure that decisions around location, nature, and timing are efficient, the transmission customer is, in fact, incentivised to lobby for an even higher level of service than what is necessary. Spreading the cost across a wide base of parties does not always lead to a suitable level of scrutiny over projects because parties who do not have sufficient exposure to charges may elect to have minimal or no involvement in the process. As Appendix C illustrates, Vector, who is the main beneficiary of NAaN, and yet faces only a portion of the costs, advocated strongly for the investment to go ahead.

9.13 These high level examples do not suggest that any party has acted inappropriately. If any of the conduct described above has taken place, it would be a predictable response to the incentives that are currently in place. It suggests that the current charges provide inefficient incentives and these would need to be corrected if parties are to have efficient incentives to propose or scrutinise investments. However, it is not necessary to point to these examples as one of the fundamentals of economics is that incentives matter. It is well-established in economics that parties tend to respond to the incentives they face in order to maximise their own self-interest.

High level analysis of the efficiency of approved Transpower investments

9.14 Once the Commerce Commission approves an investment, there can be a significant lead time before the investment takes place, or when Transpower

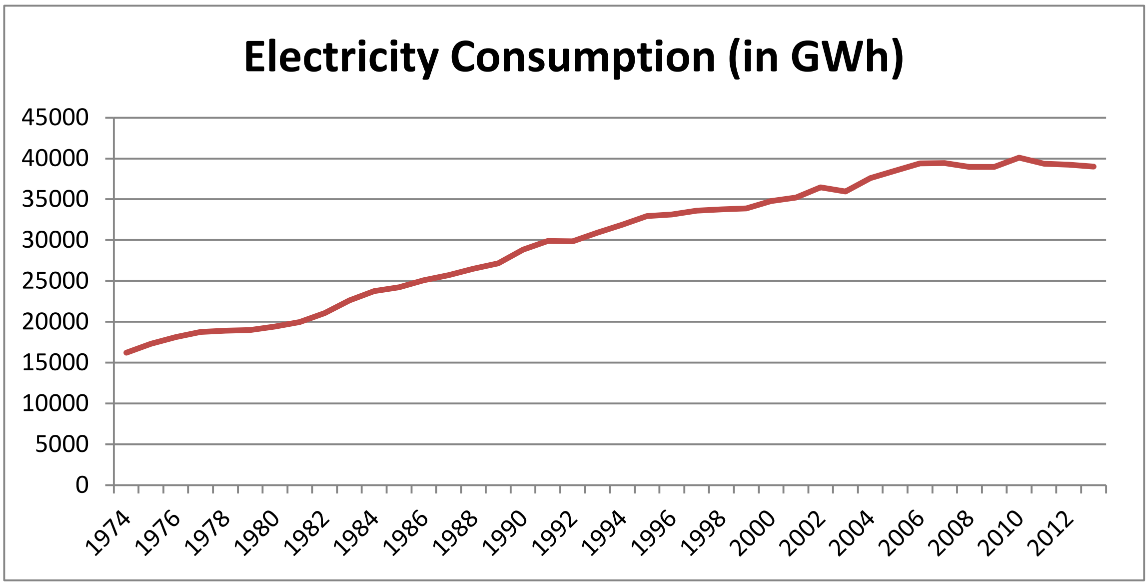
[70] While the Capital Expenditure input methodology requires consideration of transmission alternatives, a transmission alternative may not be discovered if parties are not incentivised to propose it.

[71] Arguably, consumers on Vector's, Northpower's and Top Energy's networks, plus directly connected customers north of Penrose.

financially commits to the project. During that lead time, circumstances can sometimes change, and, in particular, the need for an investment can change.

9.15 For example, in the five years leading up to the middle of 2008, Transpower announced a sizeable programme of investment in grid upgrades and expansion.[72] The Global Financial Crisis (GFC) struck the world economy from the second half of 2008. Although New Zealand was not as badly affected as many other countries, it was affected. The demand for electricity initially fell in 2008 and 2009 before returning to close to its previous levels in 2010 and remaining relatively constant, subsequently, as per Figure 3 below.[73]

Figure 3: Electricity consumption from 1974 to 2013



9.16 Despite the financial crisis and cessation of the previous pattern of steadily rising electricity demand, the Authority could find little evidence of Transpower announcing it was reviewing whether its investment proposals and approved investments required amendment in the light of changed market and financial conditions.

9.17 It is important to note that in regard to the question as to whether it is efficient to postpone an investment, the Authority's focus is on ensuring that the incentives on transmission customers are efficient. The Authority is not providing a view on whether NAaN and NIGU should have been postponed. The Authority accepts that there are many variables at play when deciding on the timing for financially committing to approved investments. For example, there may be a limited development window in relation to resource consents. However, the economic benefits achievable through efficiently postponing large transmission investments, such as NAaN and NIGU, may be considerable.

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72 This included the North Auckland and Northland Grid Upgrade (NAaN) and the North Island Grid Upgrade (NIGU).

73 See Electricity Authority, *Electricity Market Performance: 2013 Year in Review*, March 2014, p.9.

9.18 The Authority sought to understand what steps Transpower took, post-investment approval, in relation to the NAaN investments[74], to ascertain whether it would be more efficient to postpone financially committing to elements of the investment. Transpower advised as follows in relation to NAaN:

(a) "In addition to meeting load growth one of the key drivers for this investment was mitigating HILP (high impact low probability) risks. The (NAaN) project was approved on 30/4/2009 by the EC [Electricity Commission]. Six months later one of the HILP risks that we had been concerned about materialised and 280,000 customers lost supply for several hours when a forklift hit the HEN-OTA line. In late 2009 / 2010 we were, unsurprisingly, keen to mitigate the HILP risk of losing the double-circuit HEN-OTA line again.

(b) We discussed this issue in the "schedule" section of our letter of 24 March 2010 to the EC after detailed planning of the project where we make it clear the desirability of progressing and commissioning the project with minimum delay. So, while load growth was obviously an important drive of the investment so too was addressing the HILP risk and it was this concern that was driving the implementation timetable."[75]

9.19 Transpower also commented that the Clutha Upper Waitaki Lines Project (formerly known as the Lower South Island Renewables Project) was an example where Transpower conducted a post approval review of the need for part of the investment. The project consisted of five separate upgrades. Transpower advised the Authority that, given that generation had not materialised as originally expected, and due to increased uncertainty as to NZAS's ongoing demand, the three remaining upgrades were not presently required and thus Transpower postponed the remaining three upgrades, with a further review to be conducted in the second quarter of 2015. [76]

9.20 The Authority considers that, looking ahead, if transmission customers' transmission charges better reflected the costs of an investment undertaken to meet their demand, those parties may be better incentivised to seek to ensure that projects are postponed if changing circumstances suggest that it is more efficient to postpone an investment.

9.21 Table 3 provides a list of some interconnection investments that have been approved in the last few years and explores at a high level whether it might have been efficient to defer some of these investments (either before or after they were approved). The total cost of these investments is in the order of $1.6B.

9.22 The Authority has not sought to determine whether any of these investments should have been deferred. However, the Authority *is* of the view that, under the current TPM, transmission customers have inadequate incentives to seek to ensure the timing of Transpower's investments is efficient.

9.23 The table does not include:

(a) some investments that were intended to enable renewable generation

[74] The NIGU and NAaN investments were approved by the Electricity Commission.

[75] Email from Transpower to the Authority, dated 5 September 2014.

[76] Email from Transpower to the Authority, dated 5 September 2014.

(b) minor investments (under $20M)

(c) connection investments

(d) condition-based investments

(e) investments that are not primarily driven by demand and/or generation growth

(f) reactive support investments.

9.24 The column *'Economic benefit of upgrade according to SPD method, in a 2017 scenario'* is based on the modelling carried out for the beneficiaries-pay working paper.[77] It compares the net market benefit of the investment with the cost of the investment. The net market benefit is assessed according to the 'net benefit' version of the SPD method,[78] with no capping.[79] Note that the SPD method does not capture all benefits of the investment – it only includes the benefits that arise in the wholesale market. The SPD modelling is based on a 2017 scenario, in which demand is higher than at present, but some new generation is also available.[80]

9.25 The significance of this column is that:

(a) if the modelled net market benefit exceeds the cost of the investment, then the investment was probably meritorious and should not have been delayed significantly (if at all)

(b) if the modelled net market benefit is less than the cost of the investment, then it is *possible* that it would have been economic to defer, modify or cancel the investment – however further analysis would be required to determine whether this is actually the case – and if so, whether Transpower could reasonably have expected it would be the case, given the information available at the time when the investment was committed.

9.26 In considering Table 3 it is important to note the following caveats:

(a) SPD is used here just to provide a measure to assess whether there may have been benefit from deferring investment, and not because this method may provide a solution to TPM problems

(b) the capex IM does not consider SPD when assessing investments

(c) SPD does not capture reliability benefits where there is no market impact.

9.27 The key point that the Authority seeks to make is that, when deciding on the timing of investments, given their complexity and the fact that they can often be argued "*both ways*", the current transmission charges do not appear to provide adequate incentives to ensure that sufficient trained eyes and diverse but interested parties are scrutinising these investments, and considering the

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77 *Transmission pricing methodology review: beneficiaries-pay options,* Authority consultation paper, January 2014.

78 As opposed to the 'gross benefit' version of the SPD method, which considers only market benefits, not dis-benefits.

79 As opposed to other variants of the SPD method, which cap benefits on a half-hourly, daily, monthly or annual basis.

80 The 2017 scenario is described in more detail in the beneficiaries-pay working paper.

potential to defer such investments, or considering efficient non-transmission alternatives to be proposed.

Question 4: To supplement information already provided by Transpower, do you have any comments on the steps taken by Transpower or by other parties after approval of the NAaN, NIGU, and other investments such as the LSI Reliability Upgrade investments, to review whether it might have been efficient to postpone elements of them?

Question 5: To what extent do current interconnection charges promote efficient timing of investments? Please explain your response.

Table 3: Selected interconnection investments that it may have been efficient to defer

Investment	Current status	Economic benefit of upgrade according to SPD method, in a 2017 scenario[81]	Potential for deferral	Commitments made by Transpower to consider options for deferral at the approval stage
NI Grid Upgrade (NIGU)[82].	Completed.	Net market benefit estimated at $40M per year, compared to annualised cost in excess of $90M.	It might have been economic to defer some or all of the upgrade works, if it was feasible to do so. However some key commitment decisions may have been made before the 2008 GFC – at which time Transpower could not reasonably have been expected to foresee that the rate of demand growth would decline.	Transpower undertook to "review the need date for the Proposal in light of changing circumstances, including information from customers, updated Statement of Opportunities (SOOs) and the System Security Forecast (SSF)"[83].

[81] As discussed in the main text, the SPD method does not capture all the benefits of the investment.

[82] http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/#volume2 .

[83] http://www.ea.govt.nz/dmsdocument/7029 .

Investment	Current status	Economic benefit of upgrade according to SPD method, in a 2017 scenario[81]	Potential for deferral	Commitments made by Transpower to consider options for deferral at the approval stage
North Auckland and Northland Upgrade (NAaN)[84].	Completed.	Net market benefit estimated at $5M per year, compared to annualised cost in excess of $30M.	It might have been economic to defer some or all of the upgrade works, if it was feasible to do so. However some key commitment decisions may have been made before it was clear that the rate of demand growth was declining. Further, Transpower's schedule may have been constrained by interactions with Vector's investment programme.	Transpower indicated that it was "continually reviewing factors material to the justification of this project, including generation developments and demand growth". Transpower indicated that "if it became apparent that changes to the physical scope of works, design or timing of the Proposal would be of national benefit, Transpower would consider advancing, deferring or modifying the project."[85]

[84] http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/ .

[85] http://www.ea.govt.nz/dmsdocument/16449.

Investment	Current status	Economic benefit of upgrade according to SPD method, in a 2017 scenario[81]	Potential for deferral	Commitments made by Transpower to consider options for deferral at the approval stage
Lower South Island Reliability Upgrade[86].	Unclear. Transpower has already engaged in some consenting / land-related activities, but it is not clear from public sources what construction works (if any) have taken place.	Net market benefit estimated at $1.5M per year, compared to annualised cost of approximately $3M.	It may be economic to defer some elements of the investment. It is not clear to what extent Transpower has taken, or will take, advantage of opportunities for deferral.	The Authority is not aware of any such commitments.

[86] http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/.

Analysis of submissions on Transpower investment proposals

9.28 In order to further explore the existing incentives on parties to participate in Transpower's investment process, the Authority analysed participant submissions to the regulator on a sample of Transpower's investment proposals. The analysis sought to determine, at a high level, whether a party's support for an investment was correlated with that party's net benefit (i.e. a party's benefit less costs, including their share of TPM charges stemming from the investment) in relation to that investment. The analysis was undertaken to assess the extent to which the current TPM provides incentives for efficient scrutiny of investments. The results are attached in Appendix C.

9.29 Selected submissions on the following investments were analysed.

(a) Lower South Island reliability

(b) HVDC Pole 3

(c) NAaN

(d) Otahuhu GIS

(e) NIGU.

9.30 Key findings of the analysis were as follows:

(a) Transpower's major investment proposals have generally been supported by a range of parties whose share of the benefits would likely be greater than their share of the costs (and representatives of such parties) and by a range of parties who would likely achieve benefits similar to their costs.

(b) It is rare that a net beneficiary (or representative of net beneficiaries) has provided a submission that is ambivalent to, or does not support the proposal (except for reasons relating to land, consenting, undergrounding, or environmental issues). The Authority has only found two exceptions: the Employers and Manufacturers Association (North) and NZ Steel both raised concerns about Transpower's revised NIGU proposal, despite the fact that they were in the area that would benefit from the proposal.

(c) The analysis suggests support for investments is highly correlated with the level of net benefit that parties expect to receive.

(d) Where there is opposition to an investment, or support for delaying the investment or finding a cheaper option, it is generally made up of (or at least led by) parties that will pay the costs of the investment. (Again, this excludes opposition for reasons relating to land, consenting, undergrounding, or environmental issues.) Examples include:

(i) South Island generators seeking deferral of HVDC Pole 3

(ii) MEUG seeking a cheaper alternative to Otahuhu GIS

(iii) MEUG and its members querying the NIGU proposal.

9.31 For all the investments considered, distributors did not submit in opposition to the investment, even when the costs they would face as a result of the investment exceeded the benefit they and their customers would receive.[87]

9.32 Accordingly, this suggests that allocating transmission costs via a "postage stamp" methodology that spreads the costs across a range of beneficiaries and non-beneficiaries is likely to lead to less effective incentives on participants to engage in the decision-making process and to provide quality information to support the process.

9.33 However, it is also worth noting that existing TPM charges appear to have provided incentives for some participants (and in particular those that would bear (or their representative) a significant portion of the costs of the investment through their transmission charges) to provide the regulator with additional relevant information and/or analysis, or to ask pertinent questions. See, for example:

(a) Contact's submission on Pole 3 (http://www.ea.govt.nz/dmsdocument/4441), which provides information on the economics of geothermal generation

(b) Meridian's submission on Pole 3 (http://www.ea.govt.nz/dmsdocument/4880), which critiques the demand forecast used by Transpower

(c) NZIER and Strata's report, commissioned by MEUG for a NIGU consultation (http://www.ea.govt.nz/dmsdocument/6654), which raises a long list of technical issues that the regulator should consider when assessing the proposal

(d) NZIER and Strata's report, commissioned by MEUG for the Otahuhu GIS consultation (http://www.ea.govt.nz/dmsdocument/3294), which discusses possible alternatives to the proposal.

9.34 This suggests that the existing TPM does incentivise some parties to scrutinise certain Transpower investments. However, overall, the findings of the analysis suggests that better targeting of transmission costs is likely to lead to more effective incentives on participants to engage in the decision-making process and to provide quality information to support the process.

Question 6: To what extent do you consider participant support for transmission investments takes into account the cost implications for them and for other parties? To what extent do you consider the efforts made by participants to provide relevant information on transmission investments take into account the cost implications for them and for other parties?

[87] Based on the methodology employed to determine net benefit.

Kawerau investment proposal, a potential example of inefficient investment incentives

9.35 An example that appears to illustrate the role of the TPM in relation to transmission investment efficiency is the Kawerau generation export enhancement investment proposal.

9.36 Note that the Authority has used this example because it is illustrative of situations where the most efficient option might not be proposed to the Commerce Commission, thus providing the Commerce Commission with no opportunity to approve the most efficient option. The Authority has not concluded that the below example is an inefficient investment. The Authority accepts that transmission investments are complex and that other parties have more information regarding the complexities of this particular project than the Authority. Thus the Authority seeks submitter views on whether the Kawerau example is an example where the current incentives under the TPM resulted in an investment proceeding that was not the most efficient to deliver the required level of service.

9.37 The Commerce Commission was asked to approve a grid upgrade proposal at Kawerau for capital expenditure of up to $9.5M, mainly to replace a transformer with a larger 250 MVA 220/110 kV step-up transformer. The case for the replacement as an economic investment was clear, and the Commerce Commission approved Transpower's proposal.[88]

9.38 The investment was required because of an export constraint resulting from the connection of a 90MW geothermal generator to a 110 kV transmission line by Mighty River Power (MRP) at Kawerau in 2008.

9.39 However, the Authority understands that connecting directly to a nearby 220 KV line instead of the 110 KV line would have meant a new interconnection step up transformer was not required (and a cost reduction would have been realised). Note that the 110 KV and 220 KV buses are at the same physical location so the alternative location should not have presented any problems. By connecting directly to the 220 KV line, the export constraint would have been avoided, although as part of that arrangement, MRP would have been required to install a 220/22 kV step up transformer at the alternative connection location.[89]

9.40 Since the transformer that the Commerce Commission approved was an interconnection asset, MRP, being a generator in this instance, does not pay for the costs of this as the costs are recovered through the interconnection charge, which is not applied to generators. However, MRP would have been required to meet the transformer's full cost if connecting directly to the 220 KV line, as the cost would have been a component of MRP's connection charge. MRP's ability to avoid the interconnection cost provided an incentive for the inefficient option to be selected (namely connection to the 110 KV line instead of the 220 KV line). This suggests that the most efficient option was not identified by the parties in the Commerce Commission's investment approval process.[90] In fact, by the time the investment was proposed to the Commerce Commission, the most efficient

[88] The Commerce Commission's 'reasons for decision' paper was published on 18 April 2012.

[89] Instead MRP installed a smaller and less expensive 110/22 KV step up transformer MRP to connect it to the 110 KV line.

[90] While the alternative approach may have caused higher energy losses, the Authority considers that connection to the 220 KV line is likely to have been the more efficient approach.

option was no longer the most viable option as MRP had already connected to the 110 KV line.

9.41 This example suggests that if the costs of interconnection were not socialised across all interconnection customers, and instead the costs of the approved 250 MVA 220/110 kV step-up transformer better reflected the cost to serve the demand for transmission services, MRP may have been better incentivised to identify a more efficient connection option and the proposal to the Commerce Commission may not have been made.

Question 7: Do you agree that the Kawerau investment proposal described is an example of an inefficient investment resulting from the TPM? Please explain your answer.

Question 8: Do you consider that the current TPM can incentivise parties to prefer interconnection assets over connection assets or building and owning their own assets (which would require them to pay a higher portion of transmission costs)? Please explain your answer and provide any examples you may have.

Materiality

9.42 Transpower has recently completed a large capital expenditure programme and therefore the dynamic efficiency savings that might be made from an improved decision-making process might be considered limited. However, it is important to bear in mind that:

(a) capital expenditure requirements can change very quickly[91]

(b) it can take many years to change the TPM.

9.43 The materiality of the impacts of inefficient investment can be very high. The value of a five-year deferral of an investment with a cost of $200M, that would otherwise have been required in five years, is $43.5M PV (using an 8% real discount rate). Alternatively, the value of avoiding the need for an investment with a cost of $1B, that would otherwise be required in 10 years, is $463M PV (using an 8% real discount rate).

Question 9: Do you agree that the TPM can materially impact investment efficiency? Please explain why or why not.

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91 For example, new industrial load or fast take-up of electric cars, particularly where this leads to the requirement for new generation. More thermal generation closures in the Auckland region may also create the need for grid augmentation. Another example is the closure of the New Zealand Aluminium Smelter that may create a requirement for grid augmentation to facilitate transportation of greater volumes of electricity to the North Island.

10 TPM charge durability

Introduction

10.1 The statutory objective of the Authority requires it to promote efficient outcomes in the electricity industry for the long-term benefit of electricity consumers. The Authority sets out in its interpretation of its statutory objective that it believes the potential costs of regulatory uncertainty and ad-hoc interventions should be taken into account in determining minimum total costs.[92] As a consequence, the Authority is interested in promoting the durability and stability of the TPM as it believes this will promote competition, reliability and efficiency for the long-term benefit of electricity consumers.

10.2 The Authority considers that a durable TPM charge has the following attributes:

(a) **it can be applied objectively.** If the charge can be applied objectively, this reduces the requirement for time consuming, and potentially contentious, rulings and ad-hoc interventions

(b) **it can be adapted to changing patterns of grid use.** If the charge is adaptable to changing patterns of grid use, such as increasing NI to SI flows, the requirement for a further TPM review might be pushed back by many years

(c) **it avoids perverse outcomes.** If the charge avoids materially perverse outcomes, such as charges far exceeding the cost of serving customers, this could prevent expensive disputes and reduce lobbying costs.

10.3 As stated above, where a charge is not durable, this can lead to increased lobbying, disputes and calls to review the TPM. These outcomes are both costly and time consuming, and would likely adversely affect perceptions around regulatory certainty and investor confidence. Under Transpower's Individual Price Path (IPP) regulation, it is required to adhere to stringent operating expense budgets. A TPM that creates expensive disputes will not be in Transpower's interest, nor is it likely to be in the interest of any party, whether regulated or unregulated.

10.4 In its October 2012 issues paper, the Authority considered a non-durable TPM could cause lobbying and disputes and costly TPM reviews as described above.[93] This view focused on the response of large industry participants and large consumers to a non-durable TPM but not on smaller consumers, such as residential consumers, in relation to durability. This is because residential consumers do not have a collective voice (regionally), with the resources to dispute charges or lobby for TPM changes. Further, the individual consumer costs are not likely to be sufficiently large to incentivise individual lobbying.

10.5 The Authority's view as communicated in the October 2012 issues paper has been validated over the past twelve months because the Authority has had to consider two requests for ad-hoc interventions arising from the current TPM. The two instances are the request for an exemption by Transpower in relation to NAaN and a further request that was declined. One of these requests has now

[92] Paragraph A46, Appendix A, *Interpretation of the Authority's statutory objective.*

[93] Paragraph 3.2.3, p.40, October 2012 issues paper.

gone on to take the form of a request to the Courts for an ad hoc intervention. Further, Transpower has instigated an operational review to address what Transpower perceives as problems with the existing TPM. These recent developments all support the notion that the existing TPM is not durable.

10.6 The inefficiency impacts of poor durability are far reaching. For example, uncertainty around the TPM can have a consequential impact on investment decisions and dynamic efficiency. The significant resources that are used in lobbying activities, such as exemption requests and applications for changes to the TPM, hinder productive efficiency.

Durability of the HVDC charge

10.7 One component of the TPM where durability has been called into question is the current HAMI charge which recovers the costs of HVDC assets.

10.8 The charge is currently levied on SI generators that are net injectors into the grid. However, in relatively recent times, there has been an increasing tendency for southward power flows. Continuing to charge SI generators for the HVDC when it facilitates competition from their NI competitors will inevitably be controversial. The HVDC also allows lower electricity prices for both NI and SI consumers, at times. It could therefore be argued that HVDC charges should also be allocated at least partially to loads, both in the NI and SI. Unsurprisingly, the HVDC charge has been highly controversial and the subject of lobbying and disputes for many years. It is therefore unlikely to be durable. On the other hand, some submitters to the Authority's various consultations support the existing HVDC charge, given that it provides what is described as a blunt yet viable locational signal.

10.9 From a durability perspective however, the Authority considers that the HVDC charge is poorly adaptive to changing patterns of generator behaviour. It appears that, given the HVDC charge discourages SI generation, it is contributing to the trend of higher rates of new generation in the NI. This, in turn, further amplifies the durability problem.

10.10 The durability problem with the HVDC also needs to be considered in the context of charges increasing as a result of the commissioning of Pole 3. This further exacerbates risks to durability by increasing the incentive to dispute the allocation of HVDC charges.

Durability problem: cross-subsidisation of the interconnection charge across regions

10.11 The interconnection charge, being levied on all load, might be seen by some parties as objective, well understood and thus promoting certainty[94], and therefore durable. However, the Authority considers that the RCPD charge creates perverse outcomes. For example, in the NZAS/NAaN example described in section 9 above, NZAS pays a large portion of the costs of NAaN, yet its demand did not lead to the requirement for the investment, neither does it benefit from the asset, and it may even be worse off as a result of it. Where there is no relationship between the consumption of a service by a consumer and a

[94] Although there is uncertainty around the timing of periods that will be used to calculate RCPD.

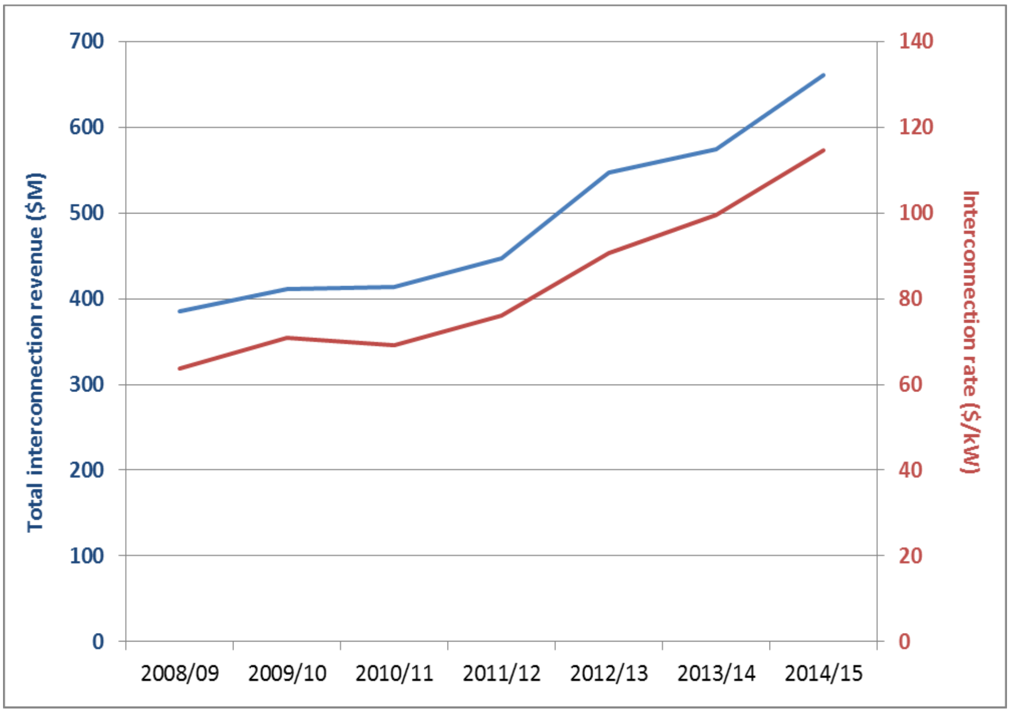
significant proportion of their interconnection charge, this is likely to result in on-going debate and lobbying if the size of the mismatch is sufficiently material.

10.12 Consider the following example which illustrates how the current RCPD charge leads to significant cross-subsidisation between the Auckland and Otago regions.

Changing interconnection charges in Auckland and Otago, before and after the NIGU investment

10.13 Both the revenue to be recovered through the interconnection charge, and the interconnection rate (in \$/kW terms)[95] have increased over the last few years (partly as a result of the NIGU upgrade) – as illustrated in Figure 4 below.

Figure 4: The interconnection rate is increasing

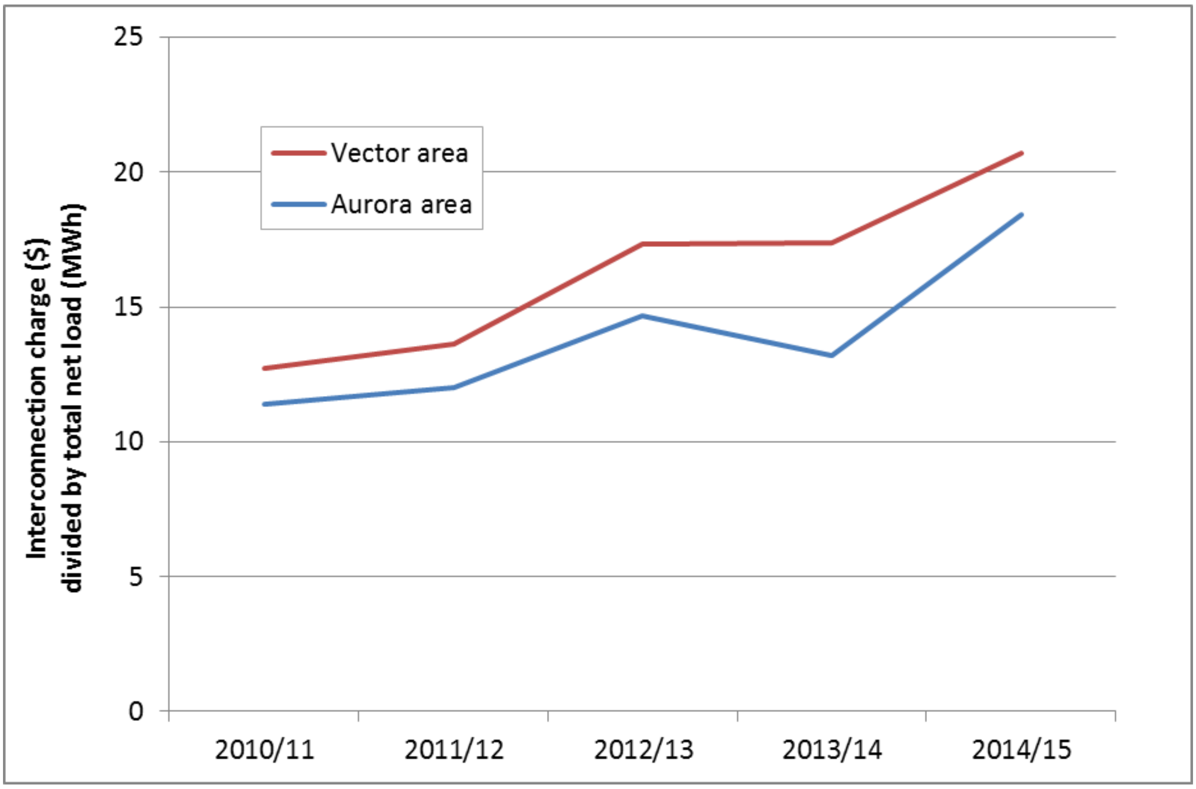


10.14 As a result, the transmission cost incurred by mass-market consumers throughout the country has increased. Figure 5 shows this trend for consumers in two areas – the Vector network area (i.e. Auckland) and the Aurora network area (i.e. Otago).

10.15 Figure 5 shows that the transmission costs incurred by Otago interconnection customers (in \$/MWh terms) has increased by over 50% in five years – even though Otago interconnection customers have derived little benefit from recent transmission upgrades.

95 This is a function of the costs to be recovered and total RCPD. See clause 29 of Schedule 12.4 of the Code.

Figure 5: Transmission costs incurred by mass-market customers are increasing



10.16 Note that:

(a) the plotted figure for pricing year X/X+1 (e.g. 2012/13) represents the ratio of the interconnection charge levied in pricing year X/X+1 (e.g. 2012/13)[96]) to the total demand in the X-1 calendar year (i.e. in this example, 2011)[97]

(b) the plotted figures are lower for Aurora customers than Vector customers – because the Aurora load is peakier, and because the Aurora area has more embedded generation relative to gross load

(c) Figure 4 and Figure 5 exclude LCE rebates.

Over-signalling RCPD potentially incentivises future disconnection from the grid

10.17 The major change the Electricity Commission made in 2008 to the TPM that Transpower adopted in the late 1990s was to allocate interconnection charges among offtake customers using their share of regional coincident peak demand (RCPD). Prior to 2008 the allocation was on the basis of each offtake customers share of anytime maximum demand (AMD). The basic idea behind both

96 which is based on demand during coincident peaks in measurement period X-2/X-1 (if the pricing year is 2012/13, the capacity measurement period will be 2010/11). Coincident peaks typically occur in the winter of year X-1 (2011 in this example).

97 Note that this above approach is intended to deal with the mismatch between pricing years, measurement periods, and calendar years. The pricing years run from 1 April to 31 March and the prices are based on regional coincident peak demands during the capacity measurement period for that pricing year, which is measured over the immediately preceding year from 1 September to 31 August. This means, for example, that if the pricing year in question is, say, the period 1 April 2014 to 31 March 2015, the prices for this period will be based on regional coincident peak demand over the period 1 September 2012 to 31 August 2013.

allocation methods is to discourage offtake customers from increasing their demand for electricity at times when demand is at or near its highest level.

10.18 Under the current RCPD approach, the calculation is based on the 12 half-hours of highest regional demand in the UNI and USI regions and on the highest 100 half-hours in the LNI and LSI regions. The purpose is to provide a stronger and more focused signal in the Upper North and Upper South Island than in the other regions. This was done because, at the time the Electricity Commission approved the current methodology, it believed the grid in these regions was closer to full capacity at times of peak usage and so there was a stronger need to provide incentives to avoid demand at these times and defer investment.

10.19 The idea behind using RCPD (and its predecessor the AMD) as the basis for allocation has some validity when grid usage is close to its maximum capacity and when demand is close to its peak level. The RCPD mechanism will discourage offtake customers from using electricity at times of peak demand and so, in circumstances where peak demand is close to capacity, will forestall the need to invest in additional grid capacity. However, if there has been, or will likely be in the foreseeable future, investment in capacity so that capacity is no longer constrained, the effect of RCPD is to promote inefficient avoidance of the grid during peaks.

Quantification of the durability problem

10.20 The Authority notes that a lack of durability of the TPM has implications for both dynamic and static efficiency. In the CBA section of the October 2012 issues paper, the Authority estimated that a durable TPM would avoid costs of $36.5M PV.[98] The avoided costs were made up of avoided dispute costs, both ongoing and periodic in nature. The Authority's estimate was heavily criticised by some submitters. For example, some submitters considered that the Authority's proposal would increase rather than decrease dispute and lobbying costs and that the Authority's assumptions regarding durability and reduction in disputation costs needed to be reassessed.[99]

10.21 The Authority has reconsidered its assessment of durability in relation to problems with the existing TPM. The Authority considers that the problem with durability is broader than that previously considered. The Authority's view is that the following costs are relevant for quantifying the durability problem of the existing TPM:

(a) ongoing and periodic dispute costs

(b) the costs of an ongoing TPM review or more regular TPM reviews

(c) the cost of any future disconnections due to parties being required to pay more than the cost of supplying their demand for transmission services

(d) dynamic efficiency effects, as uncertainty as to the future TPM has a detrimental impact on investment.

[98] Paragraphs 3.25 – 3.29, page F15, Appendix F – Cost Benefit Analysis, October 2012 issues paper.

[99] ENA submission, p.11, Genesis, Appendix C Castalia report, pp.31-32, Transpower, Appendix B, CEG report, pp.3-5.

10.22 Regarding (c) above, the costs of inefficient investment are covered in the previous section, "Promotion of efficient investment". However, disconnection as a result of an inefficient TPM is likely to have a compounding effect on durability, i.e. disconnections will cause fixed costs to be spread among a smaller base which will further compound the issue. Thus the problem caused by inefficient pricing is self-perpetuating. The significant technological changes that the industry is experiencing could exacerbate this issue.

10.23 A successful TPM review would mean that, unless a further material change in circumstances is identified, the costs of review, which have been considerable across the entire industry over (at least) the last decade, should reduce sharply.

10.24 The Authority acknowledges that quantification of the durability problem requires the Authority to exercise considerable judgement. However, given the broader consideration of durability problems described above relative to that in the October 2012 issues paper, including the dynamic efficiency impacts of a non-durable TPM chilling investment, the previous estimate of $36.5M PV is conservative.[100]

10.25 The Authority considers that there are several potential problems that impact TPM durability. The Authority is particularly interested in submitter feedback on durability and it will consider this feedback when it quantifies the durability problem in the second issues paper.

Question 10: Do you agree that cross-subsidisation of TPM costs between consumers may affect the durability of TPM charges?

Question 11: Do you consider that the current TPM is durable? Why or why not?

Question 12: Do you agree that the examples provided above are examples of a durability problem? Please explain your response.

Question 13: If you consider there to be a durability problem, do you know of any further examples of durability problems with the TPM? If so, please describe. Please also estimate the costs that you have incurred in relation to submissions on the TPM for as far in the past as you are able to provide (ie in relation to current and previous TPMs).

Question 14: Do you agree that durability is a particularly difficult problem to measure? Please explain why or why not. Are you aware of an appropriate methodology for measuring durability? If so, please provide details of that methodology.

[100] The October 2012 issues paper estimated that a benefit of $36.5M PV was achievable in relation to the Authority's TPM proposal. This paper assumes that $36.5M could also be estimated to be the size of the problem with the current TPM.

11 Inefficient generator behaviour and demand side response to interconnection and HVDC charges

Introduction

11.1 The basic premise that price does not reflect the cost of supplying a customer's demand creates the incentive for an array of inefficient generator behaviours and inefficient response of load across the grid. This inefficient behaviour, can, in turn, cause inefficiencies around the location, nature, and timing of generation and load related investments. For example, if the HVDC charge inefficiently discourages generators from operating at peak times in the SI, this may incentivise inefficient investment in generation in the NI and SI.

11.2 Inefficiencies around the location, nature and timing of generation and large load related investments, can ultimately lead to inefficient investment in transmission. For example, if generators are discouraged from locating new generation in the upper SI, then this may create a need for inefficient transmission investment between the Waitaki Valley and Christchurch.

Modelling approach and reasons

11.3 This paper provides quantitative analysis of the inefficiencies arising from the current TPM. In the context of this paper, where possible the Authority has sought to avoid using complex models such as GEM, or the linear programming or stochastic optimisation models suggested by Norske Skog.[101] These types of models can provide valuable information about the scale of the inefficiency, but are typically not the best way of explaining the inefficiency to stakeholders. The complexity of models such as GEM makes it hard for the majority of stakeholders to understand how the results are obtained.[102] Even parties that have a high level of familiarity with the model can sometimes find it difficult to understand how the results are driven by the model formulation and input assumptions. Further, when complex models are used, there is a risk that the debate will focus on the technicalities of the modelling rather than on the underlying economic argument.

11.4 Therefore, the Authority has used high level Net Present Value (NPV) analysis, incorporating scenario and sensitivity analysis in some cases, in order to explain the scale of the inefficiency in a way that can be readily understood by the majority of stakeholders.

11.5 Following the principle that it is better to avoid complex modelling when explaining the problem, the Authority has reproduced the results of TPAG's GEM analysis using a simple NPV analysis [Appendix A].

11.6 The Authority has, however, used more complex modelling in one case – see paragraphs 11.115-11.126, which seek to estimate the inefficiency that may result from the HAMI allocation of the HVDC charge causing generation and demand-side resources to operate out of merit. The Authority has used a relatively simple vSPD analysis to carry out this estimate, on the basis that it is

101 Norske Skog submission, TPAG Transmission Pricing Discussion paper, 14 July 2011. p. 3. and p. 7.

102 Darryl Biggar, Independent Review of Transmission Pricing Advisory Group: Transmission Pricing Discussion paper 7 June 2011, 14 July 2011. p. 35.

difficult to estimate the scale of the inefficiency without explicitly modelling the dispatch process.

11.7 The Authority has modelled the efficiency impacts of generator and demand side response to both the interconnection and HVDC charges. The following impacts have been investigated (note that this is not an exhaustive list of possible impacts):

Interconnection charge

(a) The RCPD allocation may over-signal the need for load shedding at peak times.

(b) The interconnection charge may over-signal the need for overall reductions in consumption.

(c) The interconnection charge may over-signal the cost of increasing Tiwai smelter production in summer.

(d) The interconnection charge may over-signal the value of embedded generation.

(e) The interconnection charge may over-signal the value of generation to direct-connect consumers.

HVDC charge

(f) The HAMI allocation may incentivise SI generators to withhold existing capacity.

(g) The HAMI allocation may discourage upgrades to SI generation capacity.

(h) The HVDC charge may discourage investment in SI grid-connected generation.

(i) The HVDC charge may bring forward the need for upper SI transmission investment.

11.8 Each of these inefficient behaviours is examined in separate sections, below.

The RCPD allocation may over-signal the need for load shedding at peak times

11.9 The current RCPD charge is based on off-take volumes at coincident peak times in four zones (UNI, LNI, USI, LSI). In the UNI and USI, 12 peaks are used for calculating charges while the number of peaks in the LNI and LSI regions is 100. The low number of peaks (12) in the UNI and USI regions was applied to discourage off-take during peak times because it was considered that by incentivising avoidance of peaks, transmission investment could be postponed or avoided. However, the number of peaks (n) used to calculate RCPD may be inefficient if there is investment in the UNI, because it may be inefficient to incentivise peak avoidance in regions with spare capacity.

Overview of inefficiencies from the interconnection charge

11.10 The RCPD allocation of the interconnection charge incentivises voluntary load shedding during potential[103] coincident peak periods. Such demand-side response has both costs and benefits. The productive efficiency effect is estimated to be somewhere between a $96M PV net cost and an $11M PV net benefit (see the detailed discussion of how these estimates were obtained in paragraphs 11.36 - 11.52).[104] This level of inefficiency is based on information provided to the Authority that suggests that there are potentially future investment requirements in the UNI and USI regions.

11.11 If there is unforeseen potential for major transmission investment to be deferred or avoided through demand-side response to RCPD charges, then the net benefit may be greater than the above estimates indicate.

11.12 The above estimates only consider the cost of load control[105] and the benefit of deferring transmission investment. Other benefits (such as deferring *distribution* investment or reducing wholesale market costs) are not included, as they can be achieved by means other than the RCPD charge.

Background to the current charge design

11.13 The Electricity Commission consulted on a proposal to introduce the RCPD allocation in 2006.[106] This consultation paper, along with supplementary material provided by Transpower,[107] set out the case for regional coincident peak charging.

11.14 The choice of regions, and the value of N used in each region, was motivated in terms of deferring two major investments:

(a) the NIGU, joining the lower NI (LNI) region to the upper NI (UNI) region

(b) an upgrade between the Waitaki Valley and Christchurch, joining the lower SI (LSI) region to the upper SI (USI) region.

11.15 N was set to 12 for the UNI and USI, in order to defer these two transmission upgrades, and to 100 for the LNI and LSI, where (in Transpower's words) "there [were] no significant transmission constraints and major new investment [was] not required".[108]

11.16 The RCPD regime was put into effect following consultation, and remains in force today.

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[103] Direct-connect consumers and distributors are incentivised to reduce load in any period that *might* turn out to be a regional coincident peak period. It is generally not possible to be sure which periods will be regional coincident peaks until after the event.

[104] Calculated as the sum of the USI and UNI effect, which is estimated to be between a $38M PV net cost and a $12M PV net benefit, and the LSI and LNI effect, which is estimated to be between a $58M PV net cost and a $1M PV net cost.

[105] This incorporates the loss of forgone production.

[106] *Transmission pricing methodology consultation paper* (Electricity Commission, November 2006).

[107] *Transmission pricing methodology supplementary material* (Transpower, June 2006).

[108] Considerations in the selection of N was discussed in Transpower's Transmission Pricing Methodology Supplementary Material, June 2006, p. 51.

11.17 The TPAG report did not cover the incentives created by the RCPD charge in great detail, but recommended that Transpower should review the design of the charge.

11.18 The Authority's October 2012 issues paper set out that the RCPD charge may be justifiable if:

(a) some transmission investment needs are driven by regional peak demand growth

(b) participants respond to the RCPD incentive, resulting in regional peak demand that is lower than it would otherwise have been

(c) the benefit of reducing the need for investment exceeds the cost of reducing demand.

11.19 The paper concluded that:

(a) the RCPD charge was probably efficient in the UNI region, on the basis that it could defer reactive support investment costing $50M–$100M by a year, achieving a deferral benefit of about $4M, at a cost of less than $2M

(b) the RCPD charge was probably inefficient in the LNI region, on the basis that it had little effect on transmission investment and caused some direct-connect consumers to unnecessarily reduce load during potential coincident peak periods, at a cost of $5M PV

(c) it was not clear whether the RCPD charge was efficient in the USI or LSI regions.

11.20 A substantial proportion of submitters endorsed the RCPD charge as providing efficient incentives for load control. However, most did not provide any new evidence relating to the efficiency of the charge – i.e.:

(a) examples of specific investments that were deferred by the RCPD charge, or

(b) information on costs incurred in responding to RCPD signals.

11.21 Norske Skog was an exception, providing information to the effect that it can reduce load in coincident peak periods without incurring material costs.[109]

11.22 Some submitters suggested specific changes to the RCPD regime – for instance, Northpower commented that the UNI should move from N=12 to N=100 now that major transmission upgrades were committed.[110] Others did not recommend specific changes, but suggested that the RCPD regime should be reviewed (generally on the basis that its signals might become excessively strong).

Key facts

11.23 In analysing whether the RCPD charge is efficient it is necessary to understand:

(a) the need for major transmission investment that might be deferred by using demand-side response to manage regional coincident peaks

(b) the cost of such demand-side response.

[109] Norske Skog submission to the October 2012 issues paper, p. 5.

[110] Northpower submission to the October 2012 issues paper, p. 3.

11.24 The Authority's current state of knowledge about the efficiency of the RCPD charge is set out in Table 4 below. Note these tables exclude the cost of demand-side response from distributed generation as this is dealt with separately in paragraphs 11.81 to 11.98.

Table 4: Key facts relating to the RCPD charge

Region	**Need for major transmission investment that might be deferred through demand-side response**	**Cost of demand-side response** *(note that this column refers to demand-side response in possible coincident peak periods, rather than overall load reductions)*
UNI	The Wairakei Ring, NIGU, NAaN and UNI dynamic reactive investments provide ample transmission capacity into the UNI and should continue to do so for many years. Transpower has advised that the main investment needed to meet UNI peak demand will be additional series capacitors on the Brownhill-Whakamaru line and/or shunt capacitors in the Auckland region, probably in the 2020s. The approximate total cost is estimated at $40M PV. A sustained 30MW reduction in UNI coincident peak demand should be sufficient to defer investment for one year, providing a deferral benefit of just over $3M PV.	The Authority: • understands that most UNI distributors use load control to manage peak demand, and that in at least some cases, this load control is in response to RCPD signals[111] • understands that NZ Steel responds to RCPD signals • does not know whether other UNI industrial loads respond to RCPD signals • does not know what costs may be incurred in the process of responding to RCPD signals.

[111] Some distributors, such as Counties Power, specifically state in their Asset Management Plans that they control load to manage their transmission charges (among other purposes). Other distributors, such as Northpower, state in their AMPs that they control peak load, but do not explicitly say that their purpose in doing so is to manage transmission charges. It is possible that, even if there was no RCPD charge, some UNI distributors might still apply load control as they do now.

Region	Need for major transmission investment that might be deferred through demand-side response	Cost of demand-side response *(note that this column refers to demand-side response in possible coincident peak periods, rather than overall load reductions)*
LNI	The Authority is not aware of any major transmission investments that could be deferred by reducing LNI coincident peak. (The Authority is aware that there will be a need for further transmission investment in the LNI region in future, but does not expect that it will be driven by regional coincident peak demand.)	The Authority: • observes that Norske Skog and PanPac respond to RCPD signals • has no information to suggest that Carter Holt Harvey, Winstone Pulp International, or Kiwirail responds to peaks • presumes that other LNI industrial loads do not respond to RCPD signals • understands that most LNI distributors use load control to manage peak demand, and that some of this load control is in response to RCPD signals[112] • has been advised that Norske Skog does not incur material costs in the process of responding to RCPD signals[113] • has been advised by PacPac that, in responding to peaks, it incurs a "modest loss of overall production" – but that its process "can accommodate short term reductions in production with no loss in quality or overall productivity"[114] • does not know what costs may be incurred by LNI distributors that respond to RCPD signals • does not know the costs consumers incur when distributors respond to these signals.

[112] Asset Management Plans indicate that most LNI distributors control peak load. Some (such as Electra, The Lines Company, and Waipa Networks) add that one of their purposes in doing so is to manage their transmission charges. Also, WEL Networks' submission to Transpower's operational review consultation indicates that it controls load to manage transmission charges.

[113] In Norske Skog's submission to Transpower's operational review consultation it submitted, "we have excess capacity in our pulp mill and are unable to operate it all the time since the paper machine cannot keep up. So we simply must shut the pulp mill down for a number of hours each day. There is no cost to do so. Nor is there a cost to do so at peak periods, rather than some other time… There is no inefficiency whatsoever."

[114] Pan Pac's submission to Transpower's operational review consultation.

Region	Need for major transmission investment that might be deferred through demand-side response	Cost of demand-side response *(note that this column refers to demand-side response in possible coincident peak periods, rather than overall load reductions)*
USI	Paragraphs 11.163 - 11.170 of this paper set out Transpower's current views on the need for investment between the Waitaki Valley and Christchurch. A sustained reduction of 12-15MW in USI coincident peak demand should be sufficient to defer investment for one year, providing a deferral benefit of just over $2M PV. The Authority is not aware of any other major transmission investment that can be deferred by reducing USI coincident peak.	The Authority: • is not aware of any major loads that face RCPD signals in this region • understands that all USI distributors work together to use load control to respond to RCPD signals • does not know what costs may be incurred by USI distributors (and their customers/consumers) in the process of responding to RCPD signals.
LSI	The Authority is not aware of any major transmission investments that could be deferred by reducing LSI coincident peak. (The Authority is aware that there will be a need for further transmission investment in the LSI region in future, but does not expect that it will be driven by regional coincident peak demand.)	The Authority: • observes (from demand data) that the Tiwai smelter does not respond in the short term to RCPD signals (although the Authority understands NZAS takes interconnection charges into account in longer term decision-making) • understands that most LSI distributors use load control to manage peak demand, and that some of this load control is in response to RCPD signals[115] • does not know what costs may be incurred by LSI distributors in the process of responding to RCPD signals.

11.25 In populating the 'transmission investment' column of the table, the Authority has relied on its understanding of material made publicly available by Transpower. It is possible that there are other major transmission investments that the Authority is not aware of, which might be deferred through demand-side response to the RCPD charge. This is particularly likely if demand growth turns out to be more rapid than expected.

[115] AMPs indicate that most LSI distributors control peak load. Some (such as Network Waitaki and Electricity Invercargill) add that one of their purposes in doing so is to manage their transmission charges.

11.26 There is also the potential for *distribution* investment to be deferred through demand-side response. However, the TPM is not the proper source of signals for such deferral. Rather, signals stem from good distributor asset management practices and Commerce Commission regulation, and are conveyed to consumers through distribution and retail tariffs. Any benefits of the RCPD charge in terms of deferring distribution investment are therefore not considered in this paper.

11.27 There is also the potential for wholesale market costs to be reduced through demand-side response, but such benefits need not be achieved through the TPM. Rather, they flow from wholesale electricity market price signals. Any benefits of the RCPD charge in terms of reducing wholesale market costs are therefore not considered in this paper.

Assessment of inefficiency – UNI and USI

11.28 In the UNI and USI regions, demand-side response during potential coincident peak periods can create both economic benefits (through deferring the need for transmission investment) and costs.

11.29 As set out in Table 4, the Authority is aware that some UNI and USI distributors respond to RCPD signals. However, the Authority does not know the magnitude of the response over and above the amount of load control that would take place if there was no RCPD charge, or the cost of responding.

11.30 For the purpose of estimating the approximate size of these benefits and costs, the Authority has considered two scenarios – in which RCPD signals bring about:

(a) a 1.5% reduction in UNI and USI coincident peak loads – enough to defer major transmission investments by one year

(b) a 5% reduction in UNI and USI coincident peak loads – enough to defer major transmission investments by three years.

11.31 These assumptions appear credible in the light of distributor asset management plan (AMP) information. AMPs show that peak load control summed across all New Zealand distributors, including all applications (not limited to responding to RCPD signals), is in the order of 5% of system peak load.[116]

11.32 Further, the Authority has considered cases in which this reduction occurs:

(a) for 20 trading periods per year, at a cost of $150/MWh

(b) for 50 trading periods per year,[117] at a cost of $1000/MWh.

11.33 The true societal cost of mass market load control (such as hot water ripple control) is unknown. In this analysis, it is assumed to be in the range from $150/MWh to $1000/MWh, where:

(a) $150/MWh is the lower of the two assumed values of the cost of load management ($150/MWh and $250/MWh) used in Energy Link's 2007 report "Load shedding analysis; study conducted for the VPWP"[118]

[116] *Electricity Line Business 2013 information disclosure compendium* (PricewaterhouseCoopers, 2013).

[117] There are only 12 RCPD periods per year in these regions – but parties may end up controlling load in more than 12 periods, because they do not know in advance which periods will be coincident peak periods.

[118] http://www.parliament.nz/resource/0000044198

(b) $1000/MWh is an approximation of the effective cost to consumers of choosing an uncontrolled tariff over a controlled tariff, as estimated in Figure 4 of Concept Consulting's 2011 report "Assessment of selected distributors' alignment against the Information Disclosure Guidelines".[119] The financial cost to a consumer of choosing not to be subject to load control may be a reasonable proxy for the societal cost of mass market load control.

11.34 These two estimates – $150/MWh and $1000/MWh – may represent a reasonable range of uncertainty about the societal cost of mass market load control. This is supported by the fact that they span $500/MWh, which is the assumed value of discretionary mass-market load in the default customer compensation scheme (under Part 9 of the Code).

11.35 Based on these assumptions, the estimated costs and benefits are summarised in Table 5.

Table 5: Estimated economic costs and benefits of response to RCPD signals in the UNI and USI[120]

Case	1.5% reduction in UNI and USI coincident peaks	5% reduction in UNI and USI coincident peaks
Load reduction for 20 periods per year, at a cost of $150/MWh	Cost – $90K per year[121] (approximately $1M PV) Benefit – $5M PV[122] Net benefit – $4M PV	Cost – $300K per year (approximately $3M PV) Benefit – $15M PV[123] Net benefit – $12M PV
Load reduction for 50 periods per year, at a cost of $1000/MWh	Cost – $1.5M per year (approximately $16M PV) Benefit – $5M PV Net cost – $11M PV	Cost – $5M per year (approximately $53M PV) Benefit – $15M PV Net cost – $38M PV

11.36 The net economic effect of short-term demand response to RCPD signals in the UNI and USI is estimated to be somewhere between a $38M PV cost and a $12M PV benefit.

11.37 The Authority cautions that the accuracy of these figures depends on assumptions about the potential to defer transmission investment – as set out in Table 3. In particular, the net benefit may be underestimated if the need for investment turns out to be greater than anticipated (and vice versa).

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119 http://www.ea.govt.nz/dmsdocument/11448

120 Note that the workings for these estimates will be provided in a separate spreadsheet on the Authority's TPM problem definition webpage.

121 20 periods per year x 0.5 hours per period x 4000MW combined peak load x 1.5% reduction x $150/MWh = $90,000 per year.

122 $3M in the UNI and $2M in the USI, from Table 4.

123 This is the $5M benefit in the previous column, which is an annual benefit, over 3 years.

Assessment of inefficiency – LNI and LSI

11.38 The Authority is not aware of any major transmission investments that might be deferred through demand-side response in the LNI or LSI.

11.39 If responding to RCPD signals does not defer transmission expenditure, then it is productively inefficient. Any economic costs incurred in the process of responding to RCPD signals – over and above the costs that would be incurred in the process of efficiently deferring distribution network investment – are inefficiencies.

11.40 The Authority observes that Norske Skog and PanPac (both in the LNI) respond to RCPD signals. It has previously estimated the economic cost of this response as $5.5M PV.[124] However, some industrials have informed the Authority that they are able to avoid peaks without any detrimental impact on efficiency. For example, Norske Skog has advised that "there is *no* loss of efficiency if load is shifted out of peak periods in order to avoid the charge". The Authority's $5.5M PV may therefore be an overestimate provided the shifting of load does not result in foregone production.

11.41 As set out in Table 2, the Authority is aware that some LNI and LSI distributors respond to RCPD signals. However, the Authority does not know the magnitude of the response (over and above the amount of load control that would take place if there was no RCPD charge) or the cost of responding.

11.42 For the purpose of estimating the approximate size of these benefits and costs, the Authority has considered two scenarios – in which RCPD signals bring about:

(a) a 1% reduction in LNI and LSI (net of Tiwai) coincident peak loads

(b) a 2.5% reduction in LNI and LSI (net of Tiwai) coincident peak loads.

11.43 Again, these assumptions appear credible in the light of distributor AMP information.

11.44 Further, the Authority has considered cases in which this reduction occurs:

(a) for 50[125] trading periods per year, at a cost of $150/MWh

(b) for 200 trading periods per year[126], at a cost of $1000/MWh.[127]

11.45 The estimated costs and benefits are summarised in Table 6.

[124] See section D3.3 of the Authority's first issues paper.

[125] 50 trading periods is considered reasonable for a party that manages peaks during particularly cold weather but otherwise does not manage peaks.

[126] There are only 100 RCPD periods per year in these regions – but parties may end up controlling load in more than 100 periods, because they do not know in advance which periods will be coincident peak periods.

[127] The justification for these cost assumptions is provided in paragraph 11.33.

Table 6: Estimated economic costs of response to RCPD signals in the LNI and LSI

Case	1% reduction in LNI and LSI (net of Tiwai) coincident peaks	2.5% reduction in LNI and LSI (net of Tiwai) coincident peaks
Load reduction for 50 periods per year, at a cost of $150/MWh	$75K per year (approximately $1M PV)	$190K per year (approximately $2M PV)
Load reduction for 200 periods per year, at a cost of $1000/MWh	$2M per year (approximately $21M PV)	$5M per year (approximately $53M PV)

11.46 Based on this analysis, the economic effect of short-term demand response to RCPD signals in the LNI and LSI is a net cost in the range from $1M PV to $58M PV, where:

(a) $1M PV is the lower end of the range in Table 6

(b) $58M PV is the upper end of the range in Table 6 ($53M PV), plus the Authority's previous estimate of the costs incurred by Norske Skog and PanPac (approx. $5M PV).

Question 15: Do you consider that the RCPD allocation provides an efficient signal of the need for load shedding at coincident peak times? Do you agree with the Authority's estimate of the possible efficiency effects?

The interconnection charge may over-signal the need for overall reductions in consumption

11.47 The previous section discusses the potential for demand-side response during coincident peak periods. However, not all consumers can respond to price signals in this way. In particular:

(a) most mass-market consumers are not exposed to RCPD price signals[128]; and

(b) some industrial consumers do not have the flexibility to reduce load on short notice.

11.48 Mass-market and inflexible industrial consumers may instead respond to interconnection charges by reducing their overall level of consumption – potentially below the level at which it is efficient for them to consume.

[128] Some are – e.g. Orion has informed the Authority that their charges reflect RCPD, at least for their larger consumers. TPM Conference transcript. 29 – 31 May 2013, p. 236. Para. 3.

11.49 Such reductions in consumption are allocatively inefficient, and will result in a small to moderate deadweight loss.[129] The deadweight loss is estimated to be in the range of $3M–$10M PV[130], over and above the smallest deadweight loss that could theoretically be achieved by allocating Transpower's costs to consumers in a different way.

11.50 If the Tiwai smelter and other industrial consumers are highly 'elastic', especially in the long run – i.e. likely to reduce consumption or close down entirely in response to increasing interconnection charges – then the deadweight loss would be much greater than shown above. An indicative estimate for highly elastic demand would be $40M PV.[131]

Previous discussion of the problem

11.51 The Authority's October 2012 issues paper found that "interconnection charges are typically passed on to mass-market customers in a variabilised form, resulting in a deadweight loss of $30M PV".[132]

Key facts

11.52 Transpower expects that in the next few years, the interconnection rate will be approximately $120–$130/kW (prior to any LCE rebates).

11.53 Direct-connect industrial consumers will pay the interconnection rate, to the extent that they cannot reduce their net demand in coincident peak periods.

11.54 Most mass-market (residential and commercial) consumers will not be directly exposed to the interconnection charge, but will still pay it in some combination of fixed and variable (per-MWh) charges.

11.55 Inflexible industrial loads, and mass-market consumers that face variabilised transmission charges, can reduce their transmission charges by reducing their overall level of consumption.

11.56 Even when mass-market consumers do not pay variabilised transmission charges, increases in the interconnection charging rate may still lead them to reduce their overall level of consumption.[133]

Assessment of inefficiency

11.57 A key parameter in deadweight loss analysis is the long-term elasticity of demand for electricity. This parameter models the propensity of consumers to reduce their electricity consumption in response to a sustained increase in the marginal price of electricity.

[129] The deadweight loss is the reduction in {consumer surplus + producer surplus} that arises from consumers (a) being deterred from using electricity even though the marginal benefit they obtain from consuming electricity exceeds the marginal cost of producing it, and/or (b) being incentivised to use electricity even though the marginal benefit they obtain from consuming electricity is less than the marginal cost of producing it.

[130] See paragraphs 11.57 - 11.74 for detail on the derivation of these estimates.

[131] See paragraphs 11.57 - 11.74 for detail on the derivation of this estimate.

[132] Workings are in Section D3.4.

[133] E.g. because a household has a fixed budget for energy costs, and any increase in the fixed component of energy costs requires a reduction in the quantity of energy consumed (and hence in variable energy costs) in order to fit within the overall budget.

11.58 The long-term elasticity of demand should not be confused with the short-term elasticity of demand, which models the propensity of consumers to react to a change in price in the short term, e.g. from one trading period to the next. The inflexible industrial and mass-market consumers discussed in this section either do not receive RCPD signals (in the case of most mass-market consumers), or have little or no short-term flexibility.

11.59 In order to calculate deadweight loss correctly, the Authority would need to know the long-term elasticity of demand for electricity (henceforth simply "elasticity") of each consumer. However, these elasticities are not known (except, perhaps, to the consumers themselves).

11.60 The Authority generally assumes that the elasticity of mass-market consumers is –0.26 – i.e. that a sustained 1% increase in the marginal cost of electricity should result in a sustained 0.26% decrease in electricity consumption, all else being equal. The exact elasticity, however, will vary between consumers and over time.

11.61 Elasticity is likely to vary widely between industrial consumers:

(a) some may be highly inelastic – i.e. they will continue to consume at the current level even if the delivered price of electricity increases or decreases markedly

(b) others may be highly elastic – i.e. if the delivered price of elasticity increases only slightly, they may reduce consumption substantially or shut down entirely.

11.62 In the absence of accurate estimates of elasticity, the Authority has used a range of assumptions to produce order-of-magnitude estimates of the possible deadweight loss.

11.63 The Authority has assumed that:

(a) **mass-market** consumers consume 30,000 GWh of electricity per year at a marginal price averaging $200/MWh, including a fully variabilised interconnection component of $20/MWh, and have an elasticity of –0.26

(b) **inelastic** industrial consumers consume X GWh[134] of electricity per year at a marginal price averaging $85/MWh, including an interconnection component that equates to $15/MWh[135], and have an elasticity of –0.09 (i.e. a third that of mass-market consumers)

(c) **elastic** industrial consumers consume Y GWh of electricity per year at a marginal price averaging $85/MWh, including an interconnection component that equates to $15/MWh, and have an elasticity of –0.78 (i.e. triple that of mass-market consumers).

[134] Possible values of X and Y are provided in paragraph 11.70 to 11.72.

[135] The variabilised interconnection charge is assumed to be lower for industrial customers than for mass-market customers – not because the industrial consumer can reduce load to avoid the charge (it is assumed that these industrial loads are too inflexible to do so), but because the industrial consumer's load shape is flatter.

11.64 The Authority has considered four scenarios where mass market consumers consume 30,000GWh and there is 6,000GWh of industrial load under the following four elasticity and consumption volume scenarios:

(a) in which X (the annual electricity consumption of inelastic industrial consumers) is 300 GWh and Y (the annual electricity consumption of elastic industrial consumers) is 300 GWh, with the 5,400 GWh balance of industrial load having the same elasticity as mass-market consumers

(b) in which X is 1,000 GWh and Y is 300 GWh, with the 4,700 GWh balance of industrial load having the same elasticity as mass-market consumers

(c) in which X is 300 GWh and Y is 1,000 GWh, with the 4,700 GWh balance of industrial load having the same elasticity as mass-market consumers

(d) in which X is 300 GWh and Y is 5,000 GWh – which would only be possible if the Tiwai smelter was in the 'elastic' category.[136] The 700 GWh balance of industrial load is assumed to have the same elasticity as mass-market consumers.

11.65 Table 7 shows the deadweight loss under each of these scenarios, both for the base case in which the elasticity of mass-market consumers is –0.26, and in sensitivities in which the elasticity of mass-market consumers is –0.13 or –0.39 (but the elasticity of industrial consumers is unchanged).

11.66 For each group of consumers in each scenario, the deadweight loss is calculated as {0.5 x variabilised interconnection charging rate x assumed reduction in consumption in response to interconnection charge}.[137] This loss is then summed over consumer groups.

[136] This is the scenario that drives the upper estimate of inefficiency. It includes an assumption that the long-term elasticity of demand for electricity of the Tiwai smelter is -0.78 – which is triple the elasticity assumed for mass-market load. In other words, it assumes that a 10% increase in the delivered cost of electricity would result in a reduction of 7.8% in the smelter's electricity consumption. The Authority does not know whether this elasticity assumption is correct, but considers that it is credible, on the basis that the Tiwai smelter's future is said to be uncertain. There must be some level of delivered electricity cost – which will depend, in turn, on factors such as aluminium prices and exchange rates – at which the smelter will reduce production. There must be some higher level of delivered electricity cost at which the smelter will shut down entirely. The Authority does not know where these thresholds lie, but considers that increases in the interconnection charge could potentially lead to one or both of them being crossed.

[137] For instance, in the first scenario and using the base case elasticity assumption of -0.26 for mass-market consumers, the deadweight loss associated with mass-market consumers is $8.7M per year – calculated as 0.5 x 867 GWh per year (the reduction in consumption arising from the variabilised interconnection charge, calculated as 30,000 GWh per year [total consumption] x -0.26 [absolute value of the elasticity] x 20/180 [the component of variable price that arises from interconnection costs, as a proportion of the total variable price]) x $20/MWh (the component of variable price that arises from interconnection costs).

Table 7: Deadweight loss ($M per year) under various scenarios

Case	Assumed elasticity of mass-market consumers	Scenario: X = Y = 300 GWh	X = 1000 GWh, Y = 300 GWh	X = 300 GWh, Y = 1,000 GWh	X = 300 GWh, Y = 5,000 GWh
Base case	–0.26	11.3	11.1	11.9	15.3
Sensitivity 1	–0.13	5.9	5.8	6.6	10.8
Sensitivity 2	–0.39	16.8	16.5	17.2	19.7

11.67 As long as consumers face variabilised transmission charges, it is inevitable that there will be some deadweight loss. The deadweight loss experienced under the current transmission charging regime is only a problem to the extent that there is some other transmission charging regime that could result in a lower deadweight loss.

11.68 In theory, the deadweight loss would be minimised by allocating interconnection charges in accordance with Ramsey pricing. Table 8 shows the level of reduction in the deadweight loss that could theoretically be achieved by moving to Ramsey pricing.

Table 8: Reduction in deadweight loss ($M per year) that could be achieved under the same scenarios

Case	Assumed elasticity of mass-market consumers	Scenario: X = Y = 300 GWh	X = 1000 GWh, Y = 300 GWh	X = 300 GWh, Y = 1,000 GWh	X = 300 GWh, Y = 5,000 GWh
Base case	-0.26	0.27	0.30	0.87	4.2
Sensitivity 1	-0.13	0.32	0.32	1.05	5.2
Sensitivity 2	-0.39	0.23	0.27	0.76	3.4

11.69 Table 8 shows that the reduction in deadweight loss is not very sensitive to the assumed elasticity of mass-market consumers, nor to the quantity of inelastic industrial demand. The key uncertainty is the quantity of elastic industrial demand – and in particular, whether Tiwai falls into the 'elastic' category.

11.70 In the first two scenarios considered (X=Y=300 GWh and X=1000 GWh, Y=300 GWh), the potential reduction in deadweight loss is only about $0.3M per year (indicatively $3M PV). Such an efficiency loss is small relative to other efficiency effects discussed in this paper.

11.71 In the third scenario (X=300 GWh, Y=1000 GWh), the potential reduction in deadweight loss is nearly $1M per year (indicatively $10M PV).

11.72 In the fourth scenario (X=300 GWh and Y=5000 GWh), the potential reduction in deadweight loss is in the order of $4M per year (indicatively, $40M PV). This scenario implicitly assumes that:

(a) the Tiwai smelter is highly elastic in the medium- to long-term, and would consume a substantially smaller amount of power under the current RCPD regime than if it was subject to a lower transmission charge

(b) such a reduction in the smelter's electricity consumption is inefficient.

11.73 If the fourth scenario was an accurate representation of reality, then reallocating transmission charges from the smelter to other consumers would support allocative efficiency.[138]

11.74 However, the Authority has not assessed the extent to which NZAS's consumption decisions depend on transmission charges, and hence which of the four scenarios most accurately describes reality.

Question 16: Do you agree that the interconnection charge may over-signal the need for overall reductions in consumption? Do you agree with the Authority's estimates of inefficiency? Which of the four scenarios, if any, do you consider the most plausible? Please explain your answer.

The interconnection charge may over-signal the cost of increasing Tiwai smelter production in summer

11.75 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.[139]

11.76 There may be other consumers directly exposed to the interconnection charge that are also deterred from seasonal operation by the charge – however, the resulting inefficiency is likely to be much smaller in scale.

Key facts

11.77 The Authority understands that NZAS may wish to increase Tiwai smelter production over summer – because electricity prices are typically lower in summer than in winter – but that the RCPD charge discourages NZAS from doing so.

11.78 If NZAS increased production substantially over the summer months, then the LSI region would likely become summer-peaking. In this case, the interconnection charges paid by NZAS would increase roughly in proportion to the increase in its summer load.

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[138] Conversely, if the smelter was *less* elastic than mass-market consumers, then reallocating transmission charges from other consumers to the smelter would support allocative efficiency.

[139] Details of the derivation of this estimate are provided in paragraphs 11.79 - 11.86.

Assessment of inefficiency

11.79 For the purpose of this analysis, the Authority will assume that NZAS has a choice between:

(a) consuming 570MW throughout the year

(b) consuming 620MW during a four-month summer period, and 570MW at other times of year.

11.80 Further assumptions are that:

(a) NZAS would purchase the additional 50MW in advance, at a price of $50/MWh[140]

(b) NZAS's mean consumption during coincident peak periods would increase from 570MW to 620MW[141]

(c) the RCPD charging rate is $120/kW

(d) increased smelter consumption during the summer months would not bring forward the need for network investment. Transpower has confirmed that this is a reasonable assumption.

11.81 On this basis, the increase in NZAS's interconnection charge would be $6M per year (before allowing for LCE rebates).

11.82 The Authority has considered three scenarios, in which the value of electricity to NZAS is:

(a) $60/MWh

(b) $70/MWh

(c) $80/MWh.

11.83 Setting aside transmission charges, the net benefit to NZAS of increasing its consumption over summer would be $1.5M, $2.9M or $4.4M per year respectively.[142]

11.84 In all three scenarios, this net benefit would be less than the increase in NZAS's interconnection charge (even once LCE rebates were allowed for).
The implication is that (under the above assumptions) NZAS increasing its production in the summer months:

(a) would be efficient for the country as a whole, but

(b) would not be cost-effective for NZAS, because of the increase in its interconnection charge.

11.85 Given the assumptions in these calculations, it is likely that NZAS would not proceed to increase its production in the summer months. The resulting productive inefficiency might lie somewhere between:[143]

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[140] Broadly consistent with 4th quarter prices on the ASX forward price curve.

[141] The implication is that the LSI region would be wholly summer-peaking. In practice, some regional coincident peaks could still occur in winter.

[142] For instance, if the value of energy to NZAS is $70/MWh, then the net benefit to NZAS of increasing its consumption over summer is $2.9M, calculated as 50MW x 2920 hours x ($70/MWh [the marginal value of electricity] – $50/MWh [the marginal cost of electricity]).

(a) $4M PV (assuming that the value of electricity to NZAS is $60/MWh, and that NZAS would only increase consumption in the next three summers)

(b) $32M PV (assuming that the value of electricity to NZAS is $80/MWh, and that NZAS would increase consumption in each of the next ten summers).[144]

11.86 There may be other consumers directly exposed to the interconnection charge that are discouraged from seasonal operation by the RCPD charge – e.g. they would prefer to consume more electricity over the winter months, but it is not cost-effective for them to do so because their interconnection bill would increase. However, the resulting inefficiency is likely to be much less than for NZAS, because NZAS consumes much more electricity than any other industrial consumer in New Zealand.

Question 17: Do you agree that the interconnection charge may over-signal the cost of increasing NZAS production in summer? Do you agree with the Authority's inefficiency assessments? Please explain why or why not.

The interconnection charge may over-signal the value of embedded generation

11.87 The interconnection charge incentivises investment in, and operation of, embedded generation. This can have both positive and negative effects on efficiency.

11.88 At this point, the Authority has not formed a final view on the extent to which the interconnection charge appropriately signals the value of embedded generation.

Previous discussion of the problem

11.89 The pricing principles in Schedule 6.4 of the Code require distributors to pay distributed generation (DG) for reductions in transmission costs that arise from connecting DG to their network. These cost reductions are referred to as the avoided costs of transmission (ACOT).

11.90 The Authority's ACOT working paper[145] found that:

(a) "ACOT payments, and the existence of DG, appear to have no observed effect on transmission investments"

(b) "although there appear to be some exceptions, ACOT payments have little observed effect on distribution investments or costs, and ACOT payments appear to provide no other material benefits to distributors" – in fact, "a prevalence of DG on some distribution networks can cause net costs to the distributor"

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[143] Using an 8% real discount rate.

[144] Three years is used on the basis that this represents the medium term while 10 years represents the long term. The PV impact of costs or savings more than 10 years in the future is minimal when the discount rate is 8%.

[145] *Transmission Pricing Methodology: avoided cost of transmission (ACOT) payments for distributed generation* (Electricity Authority consultation paper, November 2013).

(c) "the productive inefficiency that arises from DG, funded by ACOT payments, displacing more efficient generation is in the range of $6.7M to $40M PV".

11.91 Some submitters broadly agreed with these findings. Others contested them, including:

(a) explaining how DG can defer the need for network investments, including specific examples of locations where this had occurred

(b) seeking to quantify the economic benefit of DG through deferring network investments[146]

(c) pointing out other benefits of DG (such as improved reliability of supply at the local level, reduced transmission and distribution losses, and retail competition benefits).

Key facts

11.92 Because RCPD charges are treated as passed through to consumers,[147] distributors are perhaps not financially incentivised to scrutinise whether DG avoids transmission investment when determining whether to pay ACOT charges.

11.93 The ACOT working paper identified that "approximately $50M will be paid to 766MW of qualifying generation during 2013/14".[148] If these figures are correct, then the average ACOT rate was $65/kW in 2013/14. The ACOT rate can be expected to increase over time, roughly in proportion with the interconnection charging rate.

Assessment of inefficiency

11.94 In some cases, ACOT payments can result in inefficient outcomes – i.e. by incentivising investment in new DG that is less cost-effective than new grid-connected generation, and by incentivising distributed generation when there are export constraints in a region or where there are no import constraints into that region. In other cases, ACOT payments can result in efficient outcomes – e.g. by incentivising investment in new DG, and/or operation of existing DG, that defers or avoids the need for network investment.

11.95 At this point, the Authority has not formed a final view on the overall efficiency of ACOT payments.

11.96 However, it seems likely that the interconnection charge over-signals the value of net load reduction – and hence the ACOT mechanism over-signals the value of embedded generation – in some areas and under some circumstances.

11.97 For instance, incentivising new DG in an export-constrained region is unlikely to be efficient – especially if more cost-effective grid-connected generation can be constructed elsewhere in the country.

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146 See in particular *ACOT payments for distributed generation* (Andrew Shelley for the Independent Electricity Generators Association, http://www.ea.govt.nz/dmsdocument/17089) .

147 For distributors that are subject to Commerce Commission's price-quality regulation.

148 Some submitters queried the detail of these figures. They should be treated as indicative estimates only.

Question 18: Do you agree that the interconnection charge and ACOT payments may over-signal the value of embedded generation? Please explain your answer.

The interconnection charge may over-signal the value of generation to direct-connect consumers

11.98 In theory, the interconnection charge could result in an inefficiently high level of investment in generation by consumers directly exposed to the interconnection charge. However, any such efficiency loss is likely to be immaterial, relative to other efficiency effects discussed in this paper.

The interconnection charge may over-signal the value of industrial co-generation to direct-connect consumers

11.99 It is possible that consumers directly exposed to the interconnection charge might invest in additional co-generation (that is, generation whose output is physically linked to that of the consumer's industrial process), in order to reduce their interconnection charges. This could be inefficient if the new co-generation was less economic than other possible generation investments elsewhere.

11.100 However, the Authority's understanding is that consumers directly exposed to the interconnection charge have already taken advantage of the best opportunities to construct co-generation. The Authority is not aware of any consumers directly exposed to the interconnection charge that are still in a position to construct a major new co-generation facility at one of their existing sites.

11.101 It is unlikely that, given the current TPM review, a consumer directly exposed to the interconnection charge would construct a new co-generation facility on the assumption that the plant could be part-funded by avoided RCPD charges – as the RCPD charge might not continue in its present form.

11.102 The Authority notes that at least two direct-connect consumers are already able to reduce their exposure to RCPD charges by reducing their consumption during possible coincident peak periods. It seems unlikely that these particular consumers would construct new co-generation facilities in order to avoid RCPD charges, when they already have an effective means of reducing their charges.

The interconnection charge may also over-signal the value of other types of generation on a direct-connect[149] consumer's site

11.103 In theory, the interconnection charge could result in an inefficiently high level of investment by direct-connect consumers in *generation other than co-generation*. For instance, direct-connect consumers could procure gas turbines and operate these turbines to reduce their interconnection charges. This would be inefficient if the new gas turbines were less economic than other possible generation investments elsewhere.

11.104 However, this risk seems unlikely to materialise, for several reasons:

[149] Or other consumer directly exposed to the RCPD charge.

(a) the Authority has no evidence to suggest that direct-connect consumers have constructed inefficient generation in the last few years, or that they plan to construct any inefficient generation in future

(b) as noted above, it is unlikely that a consumer directly exposed to RCPD charges would procure new generation on the assumption that the plant could be part-funded by avoided RCPD charges

(c) as noted above, some consumers directly exposed to RCPD charges can reduce their RCPD charges by reducing consumption during peak periods, and so have little need to procure generation to manage RCPD charges

(d) a generation investor could probably obtain a better return by embedding its plant in a distribution network and receiving ACOT payments, than by installing its plant on a direct-connect consumer's site. This would particularly be the case if the distribution network was in the UNI (where the generator need only operate in 12 peak periods in order to earn ACOT payments) and the direct-connect consumer was in the LNI (where the generator would need to operate in 100 peak periods in order to effectively manage the consumer's RCPD charges).

Question 19: Do you agree with the Authority's assessment that, although the interconnection charge may over-signal the value of generation to direct-connect consumers, any resulting efficiency loss is likely to be relatively small? Please explain your answer.

The HAMI allocation may incentivise SI generators to withhold existing capacity

11.105 Under the HAMI methodology for determining the allocation of HVDC charges among SI generators there is a very high marginal cost when a generator offers peak capacity above their highest previous injection from a grid-connected plant. This is because they will incur additional HVDC charges for the following 5 years if dispatched (unless Transpower decides that there are exceptional operating circumstances).

11.106 This high marginal cost incentivises generators to withhold some of the capacity of existing SI grid-connected generation. It appears unlikely that such withholding would continue to the point of causing substantial efficiency losses through incentivising unnecessary investment in peaking capacity. However, it is possible that such withholding would result in out-of-merit dispatch of generation and demand-side resources. This may result in productive inefficiency in the order of $12M PV.[150]

[150] Details of the derivation of this estimate are provided in paragraphs 11.115-11.125.

Previous discussion of the problem

11.107 The Authority's October 2012 issues paper[151] set out that:

(a) the Electricity Commission's stage 2 options paper[152] had suggested that "there could be a substantial cost through disincentivising SI generators from operating their generation at full capacity"

(b) the TPAG report[153] had assessed the issue and concluded that the dispatch inefficiency was likely to be relatively immaterial (on the basis that generators would begin to offer their full capacity if and when it was needed)

(c) an earlier report by NERA[154] had also concluded that the cost of disincentivising SI generators from operating their generation at full capacity was not likely to be material.

11.108 Parties that commented on this issue in their responses to the TPAG report[155] and/or the Authority's October 2012 issues paper[156] generally agreed that the HAMI charge resulted in inefficient withholding of SI generation. There was disagreement, however, as to whether the inefficiency was material.

Results for investigation

11.109 The Authority sought information from SI generators on the extent to which the HAMI charge resulted in withholding of existing generation capacity. The responses from generators are set out below.

(a) **Contact Energy**: "Our 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 (referred to as the HAMI limit). By way of example 1MW of additional generation above the HAMI on the Clutha at the current Transpower rate, incurs a $44.6K liability, and takes 4 years to be cleared from the methodology calculation."

(b) Contact Energy generally withholds about 105MW of generation capacity on the Clutha hydro system, in order to manage its HVDC charges.

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151 *Transmission Pricing Methodology: issues and proposal,* Electricity Authority consultation paper, October 2012. See Section C5.7.

152 *Transmission Pricing Review: stage 2 options,* Electricity Commission consultation paper, July 2010.

153 *Transmission Pricing Analysis: report to the Electricity Authority,* TPAG, August 2011.

154 *New Zealand Transmission Pricing Project: a report for the New Zealand Electricity Industry Steering Group,* NERA Economic Consulting, August 2009.

155 Submissions are published at http://www.ea.govt.nz/zipcontroller/download/503332064fc5f9706dc2e8a0017d9766.

156 Submissions are published at http://www.ea.govt.nz/zipcontroller/download/89200fb50064c35dddc24c84161ec2b2 and summarised at http://www.ea.govt.nz/dmsdocument/15054.

(c) Contact only offers this capacity when Transpower declares that 'exceptional operating circumstances' (EOCs) apply – meaning that the relevant trading periods are not included when calculating Contact's AMI.[157]

(d) Contact took the view that "Transpower's ability to adjust the HAMI under an EOC makes no measurable improvement in Contact's ability to offer its full capacity, as it occurs very rarely and only for reasons of security (purchaser benefits are not considered)."

(e) **Meridian Energy**: "Meridian has a standing policy whereby Generation Controllers are alerted within the trading period if any plant may set a new HAMI limit. This allows the controller to optimise generation (sometimes across a river chain) to avoid setting a higher HAMI level as it would result in an increase in HVDC charges (presently ~ $50,000/MW/p.a.). Given this cost, increasing the HAMI must be considered carefully.

(f) Examples where the HAMI allocation has discouraged Meridian from offering the full capacity of plant as energy are:

    (i) **Manapouri**: Manapouri capacity is currently 850MW, but limited operationally to ~800MW due to a combination of transmission constraints and resource consents. The ability to operate at 800MW has been in place since September 2010. However, from September 2010 until October 2012, Manapouri Power Station had been limited by Meridian to around 730MW, which related to the previous resource consent limit. The additional 70MW capacity was not utilised. The primary reason for this was to avoid the increase in HVDC charges that would have resulted from increasing Manapouri's output above the existing HAMI limit given the uncertainty about recouping that cost. Prior to 2010, HVDC charges were a key consideration when exercising the increase in capacity resulting from the half-life refurbishment completed in 2007.

    (ii) **Benmore**: Benmore capacity is 540MW, with the current HAMI limit at ~474MW. Benmore generally offers no higher than 500MW of generation into the wholesale market, with the residual offered as reserve (meeting the market conduct requirements). If that capacity had been, or was, offered to the market as energy, it may well have improved productive efficiency via better water management across the Waitaki river chain.

(g) Meridian took the view that exemptions from Transpower at times of emergency or other system stresses do not alleviate the impact of the HAMI charge. That is, these exceptions are rare, whereas the HVDC charges impact on operation at all times."

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[157] Transpower determines when EOCs apply on a case-by-case basis. Transpower has advised that "EOCs are generally granted where the customer has acted to meet a grid owner or system operator request for generation support – provided there is a clear link between the request and that specific generator. For example:

- where the system operator has requested increased generation from that customer (or region) to mitigate a grid emergency
- where the grid owner has requested increased generation to support a planned outage or grid asset commissioning".

11.110 Trustpower indicated that they do not withhold capacity during peaks. The Authority is not aware of any other SI generators that withhold generation capacity in order to manage their HVDC charges.

Assessment of inefficiency

11.111 The HAMI allocation incentivises SI generators to withhold SI hydro capacity, which could cause inefficiency by:

(a) causing unnecessary investment in peaking capacity

(b) causing generation and/or demand-side response to operate out-of-merit.

First part of assessment – unnecessary investment in peaking generation

11.112 In theory, unnecessary investment in peaking capacity could result in substantial costs. For instance, withholding 100MW of SI hydro capacity might result in 100MW of new thermal generation being constructed, at a capital cost in excess of $100M.

11.113 However, there are several reasons why such costs are unlikely to be incurred:

(a) if the current oversupply of capacity continues for the next few years (as forecast by the system operator's Annual Security Assessment)[158], then it is unlikely that additional peaking capacity will be constructed in the near term

(b) when there is a need for capacity investment, the scarcity pricing regime will provide a strong incentive for Contact Energy and Meridian Energy to offer their full capacity into the market (to the extent that it is physically able to operate)

(c) Contact Energy and Meridian Energy may also consider offering more of their capacity in response to the recently enacted trading conduct provision, which encourages generators to "make offers in respect of all of their generating capacity that is able to operate"[159]

(d) in any case, Transpower's ability to declare Exceptional Operating Conditions (EOCs) means that withheld SI generation can still be offered if there is a grid emergency or another valid reason related to system security or transmission outage planning.

11.114 For these reasons, the Authority agrees with TPAG's conclusion that withholding of SI hydro capacity is unlikely to result in substantial efficiency losses *through incentivising unnecessary investment in peaking capacity*. However, withholding of SI hydro capacity can also lead to inefficient dispatch – as discussed below.

[158] *Security of supply annual assessment 2014,* Transpower, February 2014.

[159] Electricity Industry Participation Code Amendment (Pivotal Supply) 2014. The amendment specifies several "safe harbour criteria", the first of which is that a generator should offer all its capacity that is able to operate. Participants are not required to satisfy the safe harbour criteria – however, if they are found to have satisfied the safe harbour criteria, then they cannot be found to be in breach of the trading conduct provision.

Second part of assessment – out-of-merit dispatch

11.115 Withholding SI hydro capacity sometimes results in other generation or demand-side response that has a higher short-run marginal cost being dispatched instead – which is inefficient.

11.116 The Authority has not previously attempted to quantify this problem, but has now carried out vSPD analysis to estimate the approximate scale of the inefficiency.

11.117 The analysis does not take into account that generators may cease to withhold SI hydro capacity, either as a result of the trading conduct provision or for some other reason.

11.118 The vSPD analysis compares actual historical outcomes with a simulated scenario in which Contact and Meridian offered the full capacity of Clyde, Roxburgh and Benmore at times when they were presumed to be physically able to do so.

11.119 The modelling horizon extended from [August 2011 to July 2014]. The two scenarios considered were:

(a) actual final pricing (with one minor modification relating to frequency keeping constraints – discussed below)

(b) a simulated scenario in which Contact and Meridian offered additional capacity at Clyde, Roxburgh and Benmore into the energy market.

11.120 In the simulated scenario, the Authority introduced new energy offers of:

(a) 70 MW at Clyde, whenever the actual energy offer was between 390 and 400 MW (which is believed to be Contact's self-imposed HAMI limit, at times when EOCs do not apply)

(b) 50 MW at Roxburgh, whenever the actual energy offer was between 270 and 280 MW

(c) 60 MW at Benmore, whenever the actual energy offer was between 470 and 480 MW.

11.121 The Authority did not introduce new offers at Manapouri, on the basis the future output of the station is not expected to be restricted by HAMI limits, over and above the restrictions created by resource consent requirements.

11.122 The offer price of the introduced capacity was set to $80/MWh (reflecting the approximate long-term value of water) or the price of the highest energy offer tranche at the station in the trading period, whichever was higher.

11.123 Total station output constraints were also updated to reflect the increased capacity. Also, in both scenarios the frequency keeping constraints on the Clutha and Waitaki were relaxed – as otherwise these constraints might limit the extent to which the additional capacity would be utilised.

11.124 The difference in the vSPD objective function value between the two runs was approximately $3.5M over a three-year period, or just under $1.2M per year.[160] Based on the assumption that bids and offers are cost-reflective, this

[160] Before calculating this figure it was necessary to halve the objective function value output by vSPD, which incorporates a scaling by a factor of 2.

difference is indicative of the reduction in total annual system costs resulting from making the additional capacity available. The reduction is small relative to total wholesale market costs, but still significant in absolute terms.

11.125 The scale of the inefficiency arising from out-of-merit dispatch of South Island generation in response to the HAMI allocation is therefore estimated to be approximately $12M in PV terms.[161] This inefficiency is additional to any inefficiency that may arise from unnecessary investment in peaking capacity, as discussed above.

11.126 This estimate should be considered to be indicative only, as it is based on assumptions about the extent to which Contact and Meridian could have offered additional capacity and the costs that they would have incurred in doing so.

Question 20: Do you agree that the HAMI allocation may incentivise SI generators to withhold existing capacity? Do you agree with the Authority's estimate of inefficiency? Please explain your answer.

The HAMI allocation may discourage upgrades to SI generation capacity

11.127 The Authority considered whether the HAMI allocation of the HVDC charge deters generators from upgrading the capacity of SI grid-connected hydro generation in ways such as:

(a) refurbishing existing hydro plants to allow increased maximum output

(b) choosing lower capacity factor designs when constructing new hydro plants

(c) pursuing resource consent changes that allow increased maximum output.

11.128 This may result in productive inefficiency.

Previous discussion of the problem

11.129 The Authority's October 2012 issues paper set out that:[162]

(a) the Electricity Commission's second options paper had suggested that "there could be a substantial cost through disincentivising SI generators from investing in peaking capacity"

(b) the TPAG report had assessed the issue and concluded that "while there is potential generation investment inefficiency from discouraging new peaking capacity in the SI, the expected value of the inefficiency is likely to be [only] $8M ± $8M PV".

11.130 TPAG had reached the above conclusion on the basis of:

(a) the assumption that SI hydro generators had access to up to 200MW of capacity upgrade options, at an annualised capital cost of $65–$100/kW per year

[161] Over a 20-year period, using an 8% real discount rate

[162] See section C5.6.

(b) the assumption that these capacity upgrades could (from 2017) avoid the need for up to 140MW of new NI peaking capacity, at an annualised capital cost of $130–$150/kW per year

(c) a 50% derating to reflect the uncertainties involved.

11.131 There was little publicly available evidence, however, to support the assumption that SI hydro generators had access to up to 200MW of reasonably priced capacity upgrade options.

11.132 Submitters had relatively little to say on this point. One exception was NZIER, who argued that TPAG had overstated the scale of the inefficiency on the basis that the assumptions that the model used were unrealistic.[163]

Key facts

11.133 Over the last 16 years, Meridian has carried out upgrades, and sought resource consent changes, to increase Manapouri's peaking capacity from 585MW to 850MW.[164]

11.134 For the Benmore refurbishment (completed 2011), a decision was made not to extend the capacity from 90 to 100MW for each unit (60MW in total). The capacity upgrade (at a cost of around $1M) was not progressed, nor the associated changes to resource consents. Meridian advised that this was primarily because of the associated HVDC charges that would arise from using it.

11.135 The Waitaki station capacity is 90MW which is provided by six generation units. Meridian is currently restoring a 7th unit to service (expected 2015), which will provide flexibility and reliability benefits to the station and across the entire Waitaki river chain. However, Meridian advised the Authority that the decision to increase total output of the Waitaki station above 90MW has yet to be considered and the HAMI charge will be a factor, particularly for a unit that operates only at peaks and where the impact of increasing station capacity will last for 5 years given the way HAMI is calculated.

11.136 It may still be possible (and economic) for SI generators to increase the peaking capacity of other hydro plants.

11.137 The Authority is aware of about 240MW of consented SI hydro generation projects, and a further 200-300MW of projects that are currently in the consenting process.[165] Some of these projects may be constructed. If so, there may be cases where it is possible (and economic) for the developer to choose a design that provides additional peaking capacity.[166]

[163] http://www.ea.govt.nz/dmsdocument/11021.

[164] See e.g. http://www.meridianenergy.co.nz/assets/PDF/Company/About-us/Our-power-stations/Manapouri-online-0213.pdf.

[165] See http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWholesale%2FGeneration%2FGeneration_fleet

[166] Also known as a 'lower capacity factor design' – that is, a design which has higher nameplate capacity than the alternatives, but may not necessarily produce more electricity than the alternatives (in GWh terms).

11.138 However, the HAMI allocation of the HVDC charge tends to discourage generators (particularly generators other than Meridian[167]) from investing in peaking capacity.

Assessment of inefficiency

11.139 Contact Energy has advised the Authority that the HAMI charge "provides a disincentive to carry out efficiency upgrades which may provide additional capacity out of the existing assets", but has not provided further information about the potential costs or benefits of such upgrades. Information from other SI generators was not available at the time this paper was prepared. Accordingly, this paper does not provide a quantitative assessment of the problem.

11.140 The HVDC charge may produce an incentive to construct new NI generation in preference to new SI grid-connected generation. This is not a result of the HAMI allocation as such – rather, a consequence of levying the HVDC charge on all SI grid-connected generation. A per-MWh charge would likely have broadly the same effect.

11.141 The next two sections explore some of the efficiency effects of constructing NI generation in preference to SI.

Question 21: Do you agree that the HAMI allocation may discourage upgrades to existing SI generation capacity? Do you think this is a material problem? Please explain your answer.

The HVDC charge may discourage investment in SI grid-connected generation

11.142 The HVDC charge may encourage generation investors to construct NI generation in preference to SI grid-connected generation, even when the SI option is more cost-effective. This may result in productive inefficiency in the order of $24M PV – *if* there is a need for substantial new generation investment over the next few years.

11.143 On the other hand, if the rate of new generation investment is less than was previously expected, then the inefficiency is likely to be reduced and/or deferred. This possibility appears increasingly plausible.

Previous discussion of the problem

11.144 The Authority's October 2012 issues paper cited (and produced further evidence to support) analysis by TPAG that showed that the HVDC charge inefficiently discourages investment in SI grid-connected generation.[168] This may result in investment in NI generation that is less cost-effective.

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[167] Under the HAMI allocation, the marginal cost of increasing peak output is lower for Meridian than for other South Island generators. This is because each unit of new peaking capacity reduces the charges paid by hydro generators on their existing capacity, and Meridian has the greatest existing capacity.

[168] See Section C5.2.

11.145 The TPAG report estimated the size of the inefficiency as \$24M ± \$9M PV, based on LRMC stack modelling using five possible generation scenarios. TPAG members were divided as to whether this inefficiency was material, given the considerable uncertainty in its derivation.

11.146 Many parties that commented on this issue in their responses to the TPAG report and/or the Authority's October 2012 issues paper agreed that the HVDC charge inefficiently discourages investment in SI grid-connected generation. In particular, Contact Energy, Meridian Energy and TrustPower all commented that the HVDC charge deters them from proceeding with some SI generation investment options. The main exception was MEUG, drawing on earlier work by NZIER that argued that TPAG had overstated the scale of the inefficiency.[169]

Key facts

11.147 The HVDC charge equates to about:

(a) \$11/MWh for new SI grid-connected hydro generation with a 50% capacity factor

(b) \$13/MWh for new SI grid-connected wind generation with a 40% capacity factor.

11.148 However, the effective charge is lower for:

(a) incumbent SI hydro generators, as any charges they pay for their new generation serves to reduce the charge they pay for their existing generation

(b) all SI generators, once LCE rebates are taken into account.

11.149 The HVDC charge therefore discourages SI grid-connected generation, and leads generation investors to prefer NI generation and SI embedded generation, all else being equal.

Assessment of inefficiency

11.150 TPAG's assessment of the potential efficiency losses appears to have been reasonable, given the information available at the time. In addition to the checks already performed in 2012, the Authority has now validated TPAG's results using a 'back-of-the-envelope' analysis (Appendix A).

11.151 However, the situation has changed in key respects since TPAG carried out its analysis.

11.152 When TPAG carried out its analysis, it appeared possible that Contact Energy or Meridian Energy might proceed with major SI hydro developments in the next decade. This now seems unlikely. Contact Energy has shelved its Clutha development options, and Meridian Energy has placed the North Bank Tunnel scheme on hold. The HVDC charge can no longer be 'blamed' for inefficiently delaying these projects – since they would not proceed even if the HVDC charge was removed.

11.153 The base case of the system operator's Annual Security Assessment indicates that New Zealand currently has an excess of generation capacity.

[169] http://www.ea.govt.nz/dmsdocument/11021 .

Under the base case assumptions, little or no new generation will be required for the next few years. If this turns out to be the case, then any costs associated with discouraging SI grid-connected generation in favour of NI generation will be deferred.

11.154 Even if the current oversupply of generation is removed by decommissioning of a major thermal power station (as in the “reduced thermal generation” scenario of the system operator’s Annual Security Assessment), there appears to be a general consensus that long-term demand growth is likely to be slower than was previously thought. If this turns out to be the case, then any costs associated with discouraging SI grid-connected generation in favour of NI generation will be incurred at a slower rate.

11.155 It now appears more likely than was previously thought that the Tiwai smelter will reduce production, or close down entirely, in the next few years.[170] In either case, it is unlikely to be economic to build significant new SI generation for many years – as HVDC constraints would limit the ability to export SI surplus capacity to the NI. Discouraging new SI generation might actually be efficient in this scenario.

11.156 Therefore, TPAG’s central estimate of $24M PV may be an overestimate of the true inefficiency arising from discouraging SI generation. The true inefficiency may well lie at or below the bottom of TPAG’s range of $24M ± $9M PV.

Question 22: Do you agree that the HVDC charge may discourage investment in SI grid-connected generation? Do you agree with the Authority’s inefficiency estimate? Please explain your answer.

The HVDC charge may bring forward the need for upper SI transmission investment

11.157 The Authority's October 2012 issues paper set out that constructing NI generation in preference to SI could (for instance):

(a) defer the need for further HVDC investment (such as a fourth submarine cable)

(b) defer the need for upgrades between Bunnythorpe and Whakamaru

(c) bring forward the need for transmission upgrades to support new wind generation in the Manawatu / Wairarapa.

11.158 The Authority also considers that the HVDC charge may also bring forward the need for transmission upgrades between the Waitaki Valley and Christchurch, by discouraging generation investment in the upper SI (USI). This may result in productive inefficiency in the order of $2M–$6M PV.[171]

[170] Although more recently it has sought to increase its production over the summer months (source: Transpower TPM operational review: initial consultation paper, 9 July 2014, para 4.2.1.)

[171] See paragraphs 11.170-11.174 for the detail of the derivation of this estimate.

11.159 However, if there is an unforeseen need for major transmission investment, then the net benefit may be greater than shown above.

Previous discussion of the problem

11.160 Meridian Energy has commented that the HVDC charge may prevent efficient deferral of USI transmission investment.[172]

11.161 The Authority's October 2012 issues paper briefly noted that the HVDC charge could increase the need for additional transmission investment in the USI, but did not quantify the effect.[173]

11.162 Submitters did not comment on this issue.

Key facts

11.163 In 2013 Transpower published an update, showing its current view of the need for new investment to serve the USI.[174]

11.164 Transpower's update projected USI peak demand growth of:

(a) approximately 15MW per year beyond 2015, under a prudent demand forecast

(b) approximately 12MW per year beyond 2015, under an expected demand forecast.

11.165 Transpower's update sets out that the best option appears to be to:

(a) add two new switching stations between the Waitaki Valley and Christchurch, with a need date of:

(i) 2022 on the basis of the prudent demand forecast, or

(ii) 2030 on the basis of the expected demand forecast

(b) thermally uprate lines between the new switching stations and Islington, with a need date after 2025 on the basis of the prudent demand forecast

11.166 add new reactive support, and replace single circuit lines between Islington and the Waitaki Valley with double circuits, with a need date after 2030 on the basis of the prudent demand forecast.

11.167 The capital cost of this option is estimated at just over $30M PV.

11.168 Transpower considers it may be possible to achieve some deferral using demand-side response as a non-transmission solution.

11.169 It may also be possible to achieve some deferral by constructing new generation in the USI. The Authority is currently aware of several possible grid-connected and medium scale generation options in the area, including:[175]

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[172] https://www.ea.govt.nz/dmsdocument/17293 .

[173] See section C5.4.

[174] *Upper South Island Stage 2 information paper,* Transpower, November 2013.

[175] http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FProposed&parentDirectory=%2FDatasets%2FWholesale%2FGeneration%2FGeneration_fleet.

(a) Trustpower's medium scale Wairau and Arnold hydro projects (70 MW and 46 MW)

(b) two separate hydro projects in the Stockton area (25MW and 35MW)

(c) wind generation projects totalling over 100MW (although wind generation is of limited value in deferring transmission upgrades).

11.170 The HVDC charge may discourage investors from proceeding with these generation options, and thereby bring forward the need date for USI transmission investment.

Assessment of inefficiency

11.171 In order to place reasonable bounds on the scale of the inefficiency, the Authority has considered two scenarios:

(a) in which the HVDC charge results in USI network investment being brought forward by one year – for instance, by preventing the construction of:

  (i) a moderate-sized wind farm, perhaps Mt Cass (60MW nameplate capacity, perhaps treated as 12MW firm capacity), or

  (ii) the Stockton Plateau hydro project (25MW nameplate capacity, perhaps treated as 15MW firm capacity)

(b) in which the HVDC charge results in USI network investment being brought forward by three years – for instance, by preventing the construction of 60MW of assorted hydro generation, which might be treated as 40MW of firm capacity.

11.172 Assuming an 8% real discount rate, the deferral benefit foregone as a result of the HVDC charge is estimated to be:

(a) just over $2M in the first scenario[176]

(b) just over $6M in the second scenario.

11.173 The foregone deferral benefit is a form of productive inefficiency.

11.174 It is possible that Transpower might be able to avoid this productive inefficiency by funding new generation in the USI as a non-transmission solution. However, this contingency seems unlikely, given that Transpower has never (to date) funded new generation as a non-transmission solution.

11.175 The Authority cautions that the accuracy of these figures depends on assumptions about the need for transmission investment – as set out in under 'Key facts' above. In particular, the net benefit may be underestimated if the need for investment turns out to be greater than anticipated (and vice versa).

Question 23: Do you agree that the HVDC charge may bring forward the need for upper SI transmission investment? Do you agree with the Authority's estimate of inefficiency? Please explain your answer.

[176] $2M PV is roughly 8% of $30M PV, which is the estimated capital cost of Transpower's preferred option.

12 Problems with the prudent discount policy (PDP)

Background

12.1 The origins of the PDP are as a commercial pricing response by Transpower that sought to mitigate an unintended consequence of early TPMs that, in some circumstances, had the effect of incentivising grid users to inefficiently bypass existing grid assets with their own transmission investments. The current PDP exists to mitigate the extent to which the current TPM contains pricing signals that inefficiently incentivise the bypass of grid assets.

12.2 Granting a prudent discount involves making a judgement that inefficient bypass would actually otherwise occur. Applicants are highly incentivised to overstate benefits and underplay real costs, risks and implementation barriers. This, in addition to the fact that Transpower is able to recover from other transmission customers the revenue forgone from prudent discounts, leads to a conclusion that prudent discounts may have been granted in some early cases where actual bypass would not have in fact eventuated.

12.3 Transpower noted in its submission on the DME framework consultation paper that the current process for making a PDP application sets a very high bar, requiring applicants to establish that an uneconomic alternative investment actually exists and would very likely be implemented if a prudent discount were not granted. If the bar were set too high, or if applications that are consistent with the objectives of the policy had been declined, the Authority would expect that some uneconomic bypass would have occurred. However, there is no evidence that this has been the case.

12.4 Transpower had advised that two new prudent discount agreements have been entered into since the current TPM was introduced in 2008. Transpower informed the Authority that as the notional embedding agreements and other variants of the historical concept of a prudent discount agreement come to the end, they are being replaced by prudent discounts.

October 2012 issues paper

12.5 In its October 2012 issues paper, the Authority considered that the purpose of the PDP should be to recover Transpower's maximum allowable revenue (MAR) as efficiently as possible.

12.6 The Authority proposed a PDP to provide a backstop for dealing with specific circumstances where inefficient bypass or inefficient disconnection from the grid may occur due to the residual charge. The proposed PDP would enable Transpower to discount transmission charges where inefficient bypass or inefficient disconnection would occur, and would:

(a) apply for the expected life of the asset. This is because the duration of the discount should be sufficient to reduce incentives for generators to inefficiently disconnect from the grid so as to avoid transmission charges

(b) apply to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges, but the investment would be inefficient from an economy-wide point of view.

Feedback from submissions to the October 2012 issues paper

12.7 Some submitters agreed that a PDP was necessary. Reasons given were:

(a) to avoid inefficient load mitigation/disconnection from the grid[177]

(b) any change to the price components of any revised TPM will warrant a prudent discount policy[178]

(c) to provide incentives for generation in pragmatic logical locations[179]

(d) to facilitate innovative demand-side options to address peak demand.[180]

12.8 The Electricity Networks Association (ENA) supported continuing the PDP, extending the duration of a PDP up to the expected life of the assets involved, and widening the scope of the PDP to include generation investments, subject to reviewing the way in which this wider scope is implemented.[181]

12.9 Submissions in support of a PDP also provided comments as to necessary design features or considerations of the policy.

(a) Meridian's submission cautioned that "*It is important, then, that the prudent discount policy ensures only credible business cases for alternative projects are eligible for the prudent discount. Meridian understands that the current process Transpower applies under the prudent discount policy to determine whether an alternative project is viable is robust in this regard. This should continue under the revised prudent discount policy*."[182]

(b) Orion noted that "*the policy should be clearly stated and consideration should be given to making public any decisions under the policy*."[183]

(c) Pioneer Generation submitted that the prudent discount policy "…*is not an appropriate methodology for paying owners of embedded generation assets for the benefits accruing to network and transmission asset owners from embedded generation*."[184]

(d) Powerco submitted "*with respect to the Authority's comment that it might have expected some uneconomic bypass to have occurred if the bar is set high for prudent discount agreements, we note that there are few commercially attractive opportunities to bypass the grid apart from those that are already subject to pre-existing notional embedding agreements*."[185]

(e) CHH submitted that "*the 15 year life of present prudent discount policies is quite arbitrary and a more appropriate solution would be to have the length of a prudent discount policy to coincide with an agreed asset life*."[186]

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177 NZ Steel submission, p.11.

178 CHH submission, p.7.

179 Contact Energy submission, p.26.

180 DEUN submission, p.11.

181 ENA submission, p.30.

182 Meridian submission, p.49.

183 Orion submission, p.17.

184 Pioneer Generation submission, p.9.

185 Powerco submission, p.10.

186 CHH submission, p.7.

Feedback from submitters during conference

12.10 Contact stated that industrial consumers were unlikely to disconnect as they relied on the additional security of supply that is offered by the grid service. Thus Contact was of the view that a PDP is not required.

12.11 NZ Steel submitted that a PDP or something akin thereto is absolutely essential under the proposals as they currently come forward to ensure that the best decisions are made with reference to "NZ Inc".[187]

12.12 Some parties considered that PDPs should only be granted where the case is sufficiently robust.

12.13 Pacific Aluminium submitted that a PDP is prudent because regulators don't have perfect foresight.[188]

12.14 Transpower submitted that a PDP for notional generation was not practically achievable as it is difficult to value. According to Transpower, there are difficulties in valuing insurance, the option value, and the technical benefits of connection to the grid versus self-supply. Transpower stated that it was necessary to make a number of assumptions at a point in time, around the cost of capital, the electricity price path, around construction risk, and other technical matters. Transpower also submitted that it was particularly difficult to value geothermal because of the risks of the business.

12.15 Transpower further submitted that the requirement for a PDP is consequential to the nature of the TPM that is decided upon and that decisions around PDP should be made following other TPM related decisions, and that decisions should be made conservatively. Transpower submitted that increasing the timeframe for PDPs and providing PDPs for notional generation was excessive and that there could be unintended consequences.[189]

12.16 Contact suggested the impact of changes to other parties of the TPM on the PDP should be monitored, and that an incremental approach to changing TPM should be followed.[190]

The Authority's view

12.17 The Authority's view is that the PDP for load is an alternative to having a TPM that sets prices according to consumers' elasticity of demand.

12.18 The Authority considers that the current PDP is not adequate for dealing with inefficient response to the current TPM charging regime. However the Authority notes Transpower's comments as to the difficulty it has in valuing notional disconnection in relation to generation investments and the Authority would like to invite further submissions on the matter.

12.19 The Authority also notes Transpower's comment above that the requirement for a PDP is consequential to the nature of the TPM that is decided upon. Accordingly, the Authority will assess the need for and nature of the PDP in the second issues paper in the context of options it considers.

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[187] NZ Steel, transcripts, TPM conference.

[188] Pacific Aluminium, transcripts, TPM conference.

[189] Transpower transcripts, TPM conference.

[190] Contact, cross-submission on October 2012 issues paper.

Question 24: Do you agree with the Authority's view on the prudent discount policy? Do you agree with Transpower's view that a PDP for notional generation is not practically achievable because of the difficulties in valuing notional disconnection? Please explain your answer.

13 Conclusion

Main Findings

13.1 The Authority has re-examined the TPM problem definition and it considers that its previous problem definition (outlined in the October 2012 issues paper) could be set out more clearly. The Authority considers there are three principal problems with the current TPM, namely:

(a) the HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution, and by load

(b) the current TPM is not durable

(c) the HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry.

13.2 Fundamentally these problems arise because parties pay interconnection and HVDC charges that do not adequately reflect the cost of supplying transmission services to them. Since transmission services are provided through a network, it can be difficult to attribute the costs of providing transmission services to individual consumers, other than for connecting a customer to the grid. This means it can be difficult to set charges based on service levels delivered to each customer. As a result, a free riding problem is created whereby some parties are provided with higher levels of service but are not required to pay more. This creates incentives on those free-riding parties to seek higher levels of service. Further, given the emphasis on reliable supply under instruments such as the GRS, this is likely to lead to transmission investments earlier than is efficient and inefficient decisions around the nature, location, and timing of investments.

13.3 The over-charging and under-charging results from the way that interconnection and HVDC charges are set. In particular:

(a) *Interconnection charges*. The interconnection charge applies the same rate of charge across the grid. This rate is based on the non-HVDC and non-connection costs that Transpower is able to recover under Commerce Commission price-quality regulation rather than the costs supplying transmission services to each customer. The interconnection charge only applies to load, which means the cost of supplying interconnection services to generators is fully cross-subsidised by load.

(b) *HVDC charges*. The HVDC charge only applies to SI generators. As a consequence, the cost of supplying HVDC services to all other transmission users is cross-subsidised by SI generators.

13.4 As transmission charges do not broadly reflect the cost of supplying transmission services to each Transpower customer, this promotes inefficient investment, inefficient use of the grid, and it undermines the durability of the TPM. These three principal problems can be summarised as follows:

(a) *Inefficient investment*. Where the price a party faces for transmission services is less than the cost of meeting their demand they have an incentive to demand more transmission services than is efficient. Given the emphasis on reliable supply rather than efficient operation under instruments such as the grid reliability standards and the grid investment test, this is likely to lead to transmission investments earlier than is efficient and inefficient decisions around the nature and location of investments. In turn, this is likely to result in inefficient investment in generation, transmission alternatives, distribution, and by consumers

The Authority considers that cost socialisation of transmission charges creates ineffective incentives on parties to assist in the discovery of the most efficient transmission options (or non-transmission alternatives). The Authority has analysed some recent transmission investments and, while transmission investment decisions are complex and can often be argued "both ways", it considers that the current TPM charges fail to provide incentives for expert scrutiny of Transpower's investments, which will impede efficiency of future investment decisions. The examples provided in the paper establish why the TPM plays an important role in identification of the most efficient transmission investment option.

(b) *Poor durability*. A lack of durability of the TPM as parties are likely to have incentives to continue to lobby and push for a change to the TPM to avoid continuing to cross-subsidise the costs of meeting other parties' demand for transmission services. The Authority considers that the durability problem is broader than it previously assessed in the October 2012 issues paper. The Authority considers that the inefficiency impacts of poor durability are far reaching. For example, uncertainty around the TPM can chill investment and therefore reduce dynamic efficiency. The significant resources that are used in lobbying activities, such as exemption requests and applications for changes to the TPM, hinder productive efficiency.

(c) *Inefficient use of the grid*. This occurs because parties facing charges that are higher than the cost of supplying them with transmission services will seek to inefficiently avoid use of the grid, while those facing charges less than the cost of supplying them with transmission services will seek to use the grid more than is efficient. In turn, this is likely to drive inefficient investment (inefficient decisions around the location, nature, and timing, of investments in transmission assets, transmission alternatives, generation assets, distribution, and by load).

13.5 As a consequence, the Authority considers that the current TPM fails to promote the Authority's statutory objective of promoting efficient operation of, competition in, and reliable supply by the electricity industry for the long-term benefit of consumers.

13.6 The Authority sought to quantify these problems to the extent possible. This is summarised below.

Table 9: Quantitative assessment of the problems

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
General	The TPM fails to promote efficient investment in transmission, generation, distribution and by load.	The scale of the inefficiency has not been estimated. However we note that the potential inefficiencies are large. For example, the value of a five-year deferral of an investment with a cost of $200M, that would otherwise have been required in 5 years, is $43.5M PV (using an 8% real discount rate).
	The TPM is not durable.	May be at least $36.5M PV.
Interconnection	RCPD allocation over-signals the need for load shedding at peak times.	The economic effect of short-term demand response to RCPD signals in the LNI and LSI is estimated to be a net cost in the range from $1M PV to $58M PV. The net economic effect of short-term demand response to RCPD signals in the UNI and USI is estimated to be somewhere between a $38M PV cost and a $12M PV benefit. These estimates assume there is not an unforeseen need for major transmission investment.
	The interconnection charge may over-signal the need for overall reductions in consumption.	Inefficiency estimated to be between $3M and $40M PV.
	The interconnection charge may over-signal the cost of increasing Tiwai smelter production in summer.	Inefficiency estimated to be in between $4M and $32M PV.

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
Interconnection	The interconnection charge may over-signal the value of embedded generation.	The interconnection charge affects the investment in and operation of embedded generation in two ways: • Through setting the rate of payments in relation to the avoided cost of transmission (ACOT) • Through providing an incentive on load to invest in and operate embedded generation. The Authority has yet to complete its consideration of submissions on the ACOT working paper so has yet to reach a final position on the efficiency or otherwise of the ACOT arrangements. The matter will be addressed in the second issues paper.
	The interconnection charge may over-signal the value of generation to direct-connect consumers.	Likely to be immaterial, relative to other efficiency effects discussed in this paper.
HVDC	The HAMI allocation may incentivise SI generators to withhold existing capacity.	The inefficiency is estimated to be in the order of $12M PV. This estimate assumes that generators will continue to withhold SI hydro capacity. In practise, the trading conduct provision may discourage this.
	The HAMI allocation may discourage upgrades to SI generation capacity.	Probably small.
	HVDC charge may discourage investment in SI grid-connected generation.	May be in the order of $25M PV – *if* there is a need for substantial new generation investment over the next few years.

Transmission charge	Source of inefficiency	Estimated scale of inefficiency
HVDC	The HVDC charge may bring forward the need for upper SI transmission investment.	The deferral benefit foregone as a result of the HVDC charge is estimated to be between $2M and $6M PV – unless there is unforeseen need for major transmission investment.
Prudent discount policy (PDP)	The existing PDP may not efficiently disincentivise generators or loads from bypassing the grid.	The Authority will assess the need for and nature of the PDP in the second issues paper in the context of options it considers.

Question 25: Do you consider that there are any other material problems with the TPM (in particular, the HVDC charge, interconnection charge, and the prudent discount policy) that the Authority has not considered in this paper. If so, please provide details.

Appendix A Validation of TPAG's estimate of the inefficiency caused by discouraging SI grid-connected generation

A.1 The HVDC charge discourages SI grid-connected generation, and leads generation investors to prefer NI generation and SI embedded generation (all else being equal). This can cause productive inefficiency as a result of constructing generating plants out-of-merit. (It can also have other efficiency effects that are not covered in this Appendix – for instance, it can change the pattern of network investment, for better or worse.)

A.2 The scale of the inefficiency depends on the amount of generation that will be required, the amount of this generation that will be constructed in the NI rather than the SI as a result of the HVDC charge, and the extent to which these NI generating plants are less cost-effective than the SI alternatives.

A.3 The TPAG report estimated the size of the inefficiency as $24M ± $9M PV, based on LRMC stack modelling using five possible generation scenarios.

A.4 The approach used by TPAG is moderately complex, and therefore it is seen as useful to validate it using a simple 'back-of-the-envelope' approach.

A.5 Suppose that:

(a) 600 GWh of new generation *(i.e. approximately 1.5% of current demand)* is constructed in each year from 2016 onwards

(b) new SI generation faces an effective HVDC charge averaging $10/MWh *(depends on the level of LCE rebates)*

(c) there are some NI generation options ("marginal options") that are on average $5/MWh less cost-effective than the best available SI alternatives, and will proceed only if there is an HVDC charge

(d) the HVDC charge results in X% of new generation in any given year being drawn from "marginal options".

A.6 With an 8% real discount rate applied over 20 years:

(a) TPAG's central estimate of $24M PV can be reproduced by setting X=12%[191]

(b) TPAG's lower estimate of $15M PV can be reproduced with X=8%

(c) TPAG's upper estimate of $33M PV can be reproduced with X=17%.

A.7 Values of X from 8% to 17% appear credible, and therefore TPAG's conclusion appears reasonable given the information available at the time.

[191] $24M PV is the discounted value of a cost stream, beginning with $0.36M in 2016 (calculated as 600 GWh [amount of new generation constructed in that year] x 12% [proportion of that generation that is drawn from 'marginal options'] x $5/MWh [cost of using 'marginal options' in the North Island, in place of the best available South Island alternative]), increasing by the same amount in each subsequent year, and extending until 2033.

A.8 However, as set out in paragraph 11.152 of the main text, both the TPAG analysis and the back-of-the-envelope approach above may overstate the inefficiency – as a result of overestimating the need for new generation investment in New Zealand in the next few years.

Appendix B The role of the Commerce Commission in approving Transpower's investments

A.1 Investment approval process

The Commerce Commission is responsible for determining the capital expenditure input methodology for the submission and evaluation of Transpower's capital expenditure proposals. It took over this role on 1 November 2010, the date on which the Electricity Authority began operation. Prior to that date, from its establishment in 2003, the Electricity Commission had evaluated Transpower's capital expenditure proposals. Transpower was self-regulating in relation to investment decisions from its formation in 1994 until 2003.

The main features of the Commerce Commission's capital expenditure input methodology for Transpower are:[192]

- the capex input methodology applies to all capital intended to enter Transpower's regulatory asset base (RAB).
- in particular, the methodology applies in relation to "base capex" and "major capex"
- major capex is required to be evaluated, consulted upon, assessed and approved on a project-by-project basis in accordance with capex input methodology
- the Commission may only either approve or reject a major capex proposal
- for any major capex test to receive Commission approval, it must satisfy the investment test. The test uses cost-benefit analysis and discounting of relevant costs and benefits in the electricity market over a defined calculation period
- for a proposed investment to satisfy the investment test it must:
  - have a positive expected net electricity market benefit, unless it is designed to meet an investment need generated by the deterministic limb of the grid reliability standards. The Authority sets the grid reliability standards in the Code (see Schedule 12.2)
  - be sufficiently robust under sensitivity analysis
- in addition, the proposed investment must have the highest expected net electricity market benefit of the alternatives under consideration
- Transpower cannot substitute any major capex between individual major capex projects or to base capex
- base capex is subject to ex-ante approval (i.e. approval prior to the regulatory period). A process for determining the level of base capex approved by the Commission is specified as part of the input methodology
- substitution of base capex between years and across categories is allowed

[192] For a full description see: Commerce Commission, *Transpower Capital Expenditure Input Methodology: Reasons Paper*, January 2012.

- Transpower is required to consider transmission alternatives in its development of all major capex proposals
- a number of capital expenditure and operating expenditure incentives schemes are being put in place by the Commerce Commission for its second regulatory control period (RCP2). For example, if Transpower reduces its operating expenditure or base capex to levels below that which was approved by the Commerce Commission, Transpower is able to keep a portion of those savings (33%).[193] This incentivises Transpower to find efficiencies within its business and in its investments but it also incentivises Transpower to seek to maximise is operating expense and base capex budgets.

This regime is in most essential features the same as the investment approval regime operated by the Electricity Commission until 2010, except the Electricity Commission did not have a separate regime for scrutinising and approving base capex (such capex would be assessed under the general investment regime).

[193] Transpower is also required to meet quality targets.

Appendix C Analysis of submissions to the regulator on selected Transpower investment proposals

A.1 The Authority analysed participant submissions to the regulator on a sample of Transpower's investment proposals to determine, at a high level, whether a party's support for an investment was correlated with that party's net benefit (a party's benefit less costs, including a party's share of TPM charges stemming from the investment) in relation to that investment. The analysis was undertaken to assess the extent to which the current TPM provides incentives for efficient scrutiny of investments.

A.2 Note that:

(a) some submissions have been filtered out, for reasons noted below

(b) some assignments to categories are subjective and could be open to discussion

(c) not all rounds of consultation have been included – in particular, Transpower's own consultations are excluded in most cases.

Lower SI Reliability

Submissions to the regulator on Transpower's proposal
(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Contact Energy Meridian Energy TrustPower Powernet NZAS Fonterra Solid Energy Environment Southland Gore District Council		
Neither supported nor opposed – or had mixed views			
Prominent stakeholders that did not submit	Other distributors in the LSI area	Genesis Energy Mighty River Power Other generators and retailers MEUG	Vector Powerco Orion Other distributors outside the LSI area Norske Skog Pan Pac NZ Steel Winstone Pulp Other major users outside the LSI area
Did not support the investment, at least in the form proposed			

Note that organisations representing consumers are assigned to columns based on the benefits and costs to the consumers they represent. For instance, MEUG would be assigned to a column based on the benefits received by, and costs allocated to, MEUG members.

HVDC Pole 3

Submissions on Transpower's own GIT consultation
(http://www.ea.govt.nz/dmsdocument/4441)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment		Genesis Energy MEUG	
Neither supported nor opposed – or had mixed views			
Prominent participants that did not submit	Norske Skog Pan Pac NZ Steel Winstone Pulp Other NI major consumers Vector Powerco Other NI distributors	Mighty River Power NZAS Fonterra Other SI major consumers Orion Other SI distributors	Trustpower
Did not support the investment, at least in the form and on the timeline proposed			Meridian Energy Contact Energy *(both recommended deferral)*

It is also worth mentioning that two of the three parties that would have expected to pay the great majority of the costs of the investment – Meridian and Contact – both provided information in their submissions:

- Meridian raised key questions on demand forecasts, generation scenarios and scenario weightings, supported by factual information
- Contact commented on the economics of geothermal generation.

HVDC Pole 3

Submissions to the regulator on Transpower's proposal
(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/hvdc-grid-upgrade-proposal-call-for-submissions-history/submissions-for-hvdc-grid-upgrade-proposal-call-for-submissions/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment		Genesis Energy Mighty River Power MEUG	Contact Energy
Neither supported nor opposed – or had mixed views			
Prominent participants that did not submit	Norske Skog Pan Pac NZ Steel Winstone Pulp Other NI major consumers Vector Powerco Other NI distributors	NZAS Fonterra Other SI major consumers Orion Other SI distributors	
Did not support the investment, at least in the form proposed			Meridian Energy Trustpower

The three parties that would have expected to pay the great majority of the costs of the investment – Meridian, Contact and TrustPower – all provided information in their submissions:

- Meridian raised key questions on demand forecasts and generation scenarios, supported by factual information, and also queried whether deferral benefits could be achieved by moving the delivery date back by two years
- Contact commented on the relative weighting of the scenarios in the GIT, and implications for project timing
- Trustpower commented on the implications of increased HVDC charges for (a) operation and investment of SI generation, and (b) renewables targets.

NAaN

Submissions to the regulator on Transpower's *original* proposal

(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/#opportunityforcomment)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Northpower Vector NZ Refining Northland Regional Council Onehunga Enhancement Society Ruakaka Parish Residents and Ratepayers Assn	Contact Energy Meridian Energy Mighty River Power	
Neither supported nor opposed – or had mixed views			
Prominent stakeholders that did not submit	Major consumers in the NAaN area Other distributors in the NAaN area	Trustpower Other generators and retailers MEUG	Norske Skog Pan Pac NZ Steel Winstone Pulp Other major consumers outside the NAaN area Powerco Orion Other distributors outside the NAaN area
Did not support the investment, at least in the form proposed		Genesis Energy	

Submissions relating only to land / consenting / undergrounding issues are not included in the table

NAaN

Submissions to the regulator on Transpower's *revised* proposal

(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/#opportunityforcommentmay2008)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Northpower Vector NZ Refining	Meridian Energy	MEUG
Neither supported nor opposed – or had mixed views		Genesis Energy	
Prominent participants that did not submit	Other major consumers in the NAaN area Other distributors in the NAaN area	Contact Energy Mighty River Power Trustpower Other generators and retailers	Norske Skog Pan Pac NZ Steel Winstone Pulp Other major consumers outside the NAaN area Powerco Orion Other distributors outside the NAaN area
Did not support the investment, at least in the form proposed			

Submissions relating only to land / consenting / undergrounding issues are not included in the table.

NAaN

Submissions to the regulator on its *intention to decline* the revised proposal
(note that these submissions, and related information provided at the public conference, eventually led to Part 1 of the revised proposal being approved)
(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/north-auckland-and-northland-proposal-call-for-submissions-history/submissions-for-north-auckland-and-northland-proposal-call-for-submissions/#transpowersapplicationseptember2007)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Northpower Vector NZ Refining Auckland Regional Council Auckland City Council Kaukapakapa Res. Assn North Shore City Council Rodney District Council Waitakere City Council	Contact Energy Meridian Energy Mighty River Power NZ Council for Infrastructure Development	
Neither supported nor opposed – or had mixed views		Electricity Networks Association	MEUG
Prominent participants that did not submit	Other major consumers in the NAaN area Other distributors in the NAaN area	Genesis Energy Trustpower Other generators and retailers	Norske Skog Pan Pac NZ Steel Winstone Pulp Other major consumers outside the NAaN area Powerco Orion Other distributors outside the NAaN area
Did not support the investment, at least in the form proposed			

Submissions by Steve Goldthorpe and former Cr David Close were omitted from the table, because neither was a material beneficiary nor could plausibly be a material charge payer under any TPM.

Lower SI Renewables

Submissions to the regulator on Transpower's proposal

(https://ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Contact Energy Meridian Energy NZ Wind Energy Association	Mighty River Power	
Neither supported nor opposed – or had mixed views			
Prominent stakeholders that did not submit	Trustpower Norske Skog Pan Pac NZ Steel Winstone Pulp Other major consumers north of the constraint Vector Powerco Orion Other distributors north of the constraint	Other generators and retailers MEUG NZAS	
Did not support the investment, at least in the form proposed		Genesis Energy	

Submissions relating only to land / consenting issues are not included in the table.

Otahuhu GIS

Submissions to the regulator on Transpower's proposal

(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/consultations/grid-investment-consultations/otahuhu-proposal/submissions-for-otahuhu-proposal/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Contact Energy NZ Refining Northpower Vector Northland Regional Council Employers & Manufacturers Assn (Nth) Enterprise Northland	Meridian Energy Genesis Energy Mighty River Power NZ Council for Infrastructure Development	
Neither supported nor opposed – or had mixed views			
Prominent participants that did not submit	NZ Steel Other major consumers and distributors in and north of Auckland	Trustpower Other generators and retailers	Norske Skog Pan Pac Winstone Pulp Other major consumers south of Auckland Powerco Orion Other distributors south of Auckland
Did not support the investment, at least in the form proposed			MEUG NZAS Norske Skog

NIGU

Submissions to the regulator on its *intention to decline* Transpower's *original* proposal

(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/consultations/grid-investment-consultations/auckland-400-kv-grid-investment-proposal-draft-decision/submissions-for-auckland-400-kv-grid-investment-proposal-draft-decision/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Meridian Energy Mighty River Power Vector Northpower	NZ Council for Infrastructure Development	Contact Energy Unison
Neither supported nor opposed – or had mixed views	Auckland Regional Council	Counties Power University of Auckland	Genesis Energy
Prominent participants that did not submit	Trustpower NZ Steel Other major consumers and distributors in and north of Auckland	Other generators and retailers	Norske Skog Pan Pac Winstone Pulp Other major consumers south of Auckland Powerco Orion Other distributors south of Auckland
Did not support the investment, at least in the form and on the timeline proposed		3M *(cable provider)*	MEUG NZAS

Submissions driven primarily by land / consenting / undergrounding/ environmental issues are not included in the table.

The table omits all submissions by private individuals – most of which are motivated by land / consenting issues – because these individuals do not derive significant benefit from the investment, and could not plausibly pay a substantial share of the cost under any transmission pricing methodology.

NIGU

Submissions to the regulator on Transpower's *revised* proposal

(http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/dev-archive/consultations/grid-investment-consultations/north-island-grid-upgrade-project/submissions-for-the-north-island-grid-upgrade-project/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Meridian Energy Mighty River Power Auckland Intl Airport Vector Northpower Auckland City Council North Shore City Council Enterprise Northland	WEL Networks Electricity Networks Assn NZ Wind Energy Assn University of Auckland NZ Council for Infrastructure Development	Contact Energy Genesis Energy
Neither supported nor opposed – or had mixed views	Employers & Manufacturers Assn (Nth)		Orion Unison
Prominent participants that did not submit	Trustpower Other major consumers and distributors in and north of Auckland	Other generators and retailers	Other major consumers south of Auckland Powerco Other distributors south of Auckland
Did not support the investment, at least in the form and on the timeline proposed	NZ Steel	Todd Energy Business NZ 3M *(cable provider)*	MEUG NZAS Norske Skog PanPac Winstone Pulp Wood Processors Assn

Submissions driven primarily by land / consenting / undergrounding/ environmental issues are not included in the table.

The table omits all submissions by private individuals – most of which are motivated by land / consenting issues – because these individuals do not derive significant benefit from the investment, and could not plausibly pay a substantial share of the cost under any transmission pricing methodology.

NIGU

Submissions to the regulator on its *intention to approve* the revised proposal
(Summary of submissions at http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/written-submissions-and-public-conference-process-history/)

	Likely share of benefits is *greater than* likely share of costs	**Share of benefits is *similar to* share of costs, or comparison is unclear**	**Likely share of benefits is *less than* likely share of costs**
Supported the investment	Meridian Energy Mighty River Power Ports of Auckland Vector		Genesis Energy
Neither supported nor opposed – or had mixed views			
Prominent stakeholders that did not submit	Trustpower Other major consumers and distributors in and north of Auckland	Other generators and retailers	Contact Energy NZAS Other major consumers south of Auckland Powerco Other distributors south of Auckland
Did not support the investment, at least in the form and on the timeline proposed		Capital Turbines NZ *(turbine provider)* 3M *(cable provider)*	MEUG Winstone Pulp

Submissions driven primarily by land / consenting / undergrounding/ environmental issues are not included in the table.

The table omits all submissions by private individuals – most of which are motivated by land / consenting issues – because these individuals do not derive significant benefit from the investment, and could not plausibly pay a substantial share of the cost under any transmission pricing methodology.

Appendix D Submitter Questions

Question 1: Do you agree that, in relation to decisions around transmission pricing, the Authority should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers? Why or why not?
Question 2: Do you agree with the Authority's view on what constitutes an efficient charge? What role do you consider durability plays in determining efficient charges? Please explain your answers.
Question 3: Do you agree with the Authority's revised position on the problem definition, described above? Please explain your answer.
Question 4: To supplement information already provided by Transpower, do you have any comments on the steps taken by Transpower or by other parties after approval of the NAaN, NIGU, and other investments such as the LSI Reliability Upgrade investments, to review whether it might have been efficient to postpone elements of them?
Question 5: To what extent do current interconnection charges promote efficient timing of investments? Please explain your response.
Question 6: To what extent do you consider participant support for transmission investments takes into account the cost implications for them and for other parties? To what extent do you consider the efforts made by participants to provide relevant information on transmission investments take into account the cost implications for them and for other parties?
Question 7: Do you agree that the Kawerau investment proposal described is an example of an inefficient investment resulting from the TPM? Please explain your answer.
Question 8: Do you consider that current TPM can incentivise parties to prefer interconnection assets over connection assets or building and owning their own assets (by which they will be required to pay a higher portion of transmission costs)? Please explain your answer and provide any examples you may have.
Question 9: Do you agree that the TPM can materially impact investment efficiency? Please explain why or why not.
Question 10: Do you agree that cross-subsidisation of TPM costs between consumers is an important consideration when considering the durability of TPM charges?
Question 11: Do you consider that the current TPM is durable? Why or why not?
Question 12: Do you agree that the examples provided above are examples of a durability problem? Please explain your response.

Question 13: If you consider there to be a durability problem, do you know of any further examples of durability problems with the TPM? If so, please describe. Please also estimate the costs that you have incurred in relation to submissions on the TPM for as far in the past as you are able to provide (ie in relation to current and previous TPMs).
Question 14: Do you agree that durability is a particularly difficult problem to measure? Please explain why or why not. Are you aware of an appropriate methodology for measuring durability? If so, please provide details of that methodology.
Question 15: Do you consider that the RCPD allocation provides an efficient signal of the need for load shedding at coincident peak times? Do you agree with the Authority's estimate of the possible efficiency effects?
Question 16: Do you agree that the interconnection charge may over-signal the need for overall reductions in consumption? Do you agree with the Authority's estimates of inefficiency? Which of the four scenarios, if any, do you consider the most plausible? Please explain your answer.
Question 17: Do you agree that the interconnection charge may over-signal the cost of increasing Tiwai smelter production in summer? Do you agree with the Authority's inefficiency assessments? Please explain why or why not.
Question 18: Do you agree that the interconnection charge and ACOT payments may over-signal the value of embedded generation? Please explain your answer.
Question 19: Do you agree with the Authority's assessment that, although the interconnection charge may over-signal the value of generation to direct-connect consumers, any resulting efficiency loss is likely to be relatively small? Please explain your answer.
Question 20: Do you agree that the HAMI allocation may incentivise SI generators to withhold existing capacity? Do you agree with the Authority's estimate of inefficiency? Please explain your answer.
Question 21: Do you agree that the HAMI allocation may discourage upgrades to SI generation capacity? Do you think this is a material problem? Please explain your answer.

Question 22: Do you agree that the HVDC charge may discourage investment in SI grid-connected generation? Do you agree with the Authority's inefficiency estimate? Please explain your answer.
Question 23: Do you agree that the HVDC charge may bring forward the need for upper SI transmission investment? Do you agree with the Authority's estimate of inefficiency? Please explain your answer.
Question 24: Do you agree with the Authority's view on prudent discount policy? Do you agree with Transpower's view that a PDP for notional generation is not practically achievable because of the difficulties in valuing notional disconnection? Please explain your answer.
Question 25: Do you consider that there are any other material problems with the TPM (in particular, the HVDC charge, interconnection charge, and the prudent discount policy) that the Authority has not considered in this paper? If so, please provide details.