

Transmission Pricing Advisory Group

# Transmission pricing discussion paper

For consultation

7 June 2011

**Note:** This paper has been prepared by the Transmission Pricing Advisory Group. Content should not be interpreted as representing the views or policy of the Electricity Authority.



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## Executive summary

### Introduction

1. The Electricity Authority (Authority) is continuing the Transmission Pricing Review (Review) initiated by the Electricity Commission (Commission). It formed the Transmission Pricing Advisory Group (TPAG) to provide advice on a recommended option for the Transmission Pricing Methodology (TPM) and associated Guidelines if a change from the status quo is the preferred option.
2. A key aspect of the TPAG role is to publish a discussion paper for consultation which sets out TPAG's analysis and recommendations (Discussion Paper). This paper is the TPAG's Discussion Paper and the TPAG invites submissions on the analysis and recommendations described in it.

### Background to transmission pricing and the Review

3. Transpower's total transmission revenue requirement is regulated by the Commerce Commission. The TPM is a methodology regulated by the Authority that determines how the total revenue requirement is allocated between, and recovered from, Transpower's customers. The challenge is to allocate transmission costs in a way that encourages efficient use of the transmission network, operation of the electricity market and coordination of investment in generation, load and transmission.
4. The Commission established the Review in early 2009 as a three stage project and undertook the first two stages, each of which culminated in a consultation paper. The Authority was established on 1 November 2010 and took responsibility for the Review from that date and is undertaking the third stage: the identification of a preferred option for the TPM.
5. The first stage of the Review investigated efficient pricing theory, international experience and issues with the current TPM, and identified high level options for the TPM. The focus was on whether there was justification to consider enhanced locational signalling in addition to that provided by nodal pricing, deep connection and the grid investment test.
6. The second stage of the Review drew on submitters' views and analysis of the potential benefits of locational signalling. The stage 2 consultation paper signalled two important provisional conclusions:
  - there does not appear to be a demonstrable benefit from enhanced locational signalling to grid users to defer economic transmission investments through transmission charges; and
  - there appears to be a possible benefit in options that incentivise action to avoid or defer reliability-driven investments (for example, through investment in generation or load management).
7. The stage 2 consultation paper noted that there was unlikely to be merit in pursuing high-level options that enhanced locational signalling for economic transmission investments and suggested options for other aspects of the TPM:
  - incentivising the deferral of reliability transmission investments;



- the allocation of High Voltage Direct Current (HVDC) costs; and
  - static reactive compensation (SRC).
8. The TPAG has spent some time understanding and testing the stage 2 analysis of the value of locational signalling for economic transmission investment as the conclusions leading from this analysis have been pivotal to the direction of the Review and the work of the TPAG. The TPAG agrees with the Commission's provisional conclusion that there does not appear to be demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments.

### Regulatory context for the Review

9. The Commission commenced the Review under the jurisdiction of the Electricity Act 1992 but on 1 November 2010 the Commission was succeeded by the Authority as one of a number of sector changes introduced under the Electricity Industry Act 2010 (the Act). The Authority is now continuing the Review under the new regulatory arrangements which include a new statutory objective for the Authority and the Electricity Industry Participation Code (the Code) which replaced the Electricity Governance Rules 2003 (Rules).
10. The establishment of the Authority with a new statutory objective led to a reconsideration of the decision framework that underpinned previous decisions about the TPM and in particular the ongoing relevance of the pricing principles contained in the Rules and transferred to the Code. As part of a separate Review work stream the Authority reviewed the ongoing relevance of the pricing principles. Following consultation, the Authority has removed the pricing principles from the Code with effect from 1 June 2011.
11. The regulatory framework for the TPM post 1 June 2011 requires that the Guidelines and TPM must be consistent with the Act and relevant parts of the Code.
12. Because the TPM is a schedule to the Code, any proposal to amend the existing TPM must ultimately be progressed as a Code amendment, and so the Code Amendment Principles (CAPs) developed by the Authority are an important input to TPAG's analysis framework.
13. The TPAG has been concerned to ensure that work undertaken, and the TPM options developed by, the Commission are consistent with the new statutory framework. The TPAG concludes that the changes to the statutory framework during the course of the Review do not require the Commission's analysis and development of alternative options to be reworked and that the options developed through the initial stages of the Review were developed in a manner consistent with the Authority's statutory objective.

### Analysis framework

14. The TPAG's analysis framework is based on the statutory objective as it is applied by the CAPs.
- CAP 1 – Lawfulness: Does the proposed change come within the Authority's jurisdiction and is it consistent with the statutory objective? Consistency with the statutory objective is tested through the application of CAPs 2 and 3.
  - CAP 2 – Is there a clearly identified: efficiency gain; regulatory failure; or market failure which warrants analysis of alternative options for the long term benefit of consumers?

- CAP 3 – Quantitative cost benefit analysis of alternative.
15. To provide structure to its consideration of the costs and benefits of the options, the TPAG has identified a number of efficiency considerations.
  16. **Efficiency consideration 1: Beneficiary pays.** There are benefits of applying a beneficiary pays approach to allocating the costs of transmission assets through improved investment decision-making and improved durability of the methodology. However, there are issues to consider in applying a beneficiary pays approach in order to secure these benefits. In particular, applying a beneficiary pays approach requires a robust method to clearly and objectively identify beneficiaries and the value of their benefits. Further explanation of beneficiary pays is given from paragraph 4.3.4.
  17. **Efficiency consideration 2: Locational price signalling.** Locational price signalling can incentivise: efficient co-ordination of generation, demand-side and transmission investment and efficient dispatch of generation and operation of demand side management (DSM); and efficiency trade-offs between the costs and benefits of reliability.
  18. **Efficiency consideration 3: Unintended efficiency impacts.** Allocation methodologies have the potential to introduce unintended price signals that may impact on efficient investment in generation, Demand Side Management (DSM) and transmission, economic dispatch, the use of sunk transmission assets and incentives to shift costs between participants with no efficiency gain.
  19. **Efficiency consideration 4: Competitive neutrality.** An allocation methodology should provide a level playing field for new investments.
  20. **Efficiency consideration 5: Implementation and operational costs.** Different methodologies will incur implementation and operational costs for industry participants, Transpower and the Authority.
  21. **Efficiency consideration 6: Good regulatory practice.** Good regulatory practice should seek regulation that is transparent, easily understood, defensible, certain and provides for consistent outcomes over time.

### Scope of the TPAG's work

22. The scope of the TPAG's work has been governed by its terms of reference and by the scope of the stage 1 and 2 analysis and stakeholder submissions.
23. The TPAG's work has focused on options for HVDC cost allocation, shallower or deeper connection and static reactive compensation. The assessment of each of these areas steps through:
  - issues arising with status quo that might indicate market or regulatory failure or the opportunity for efficiency gains for the long term benefit of consumers (CAP 2);
  - possible options designed to remedy the regulatory or market failures or enable efficiency gains;
  - identifying costs and benefits of the options (CAP 3); and
  - comparing the costs and benefits of the options relative to a counterfactual based on the status quo (CAP 3).

## Assessing options for HVDC cost allocation

24. The TPAG's analysis of the current allocation HVDC costs in order to establish whether there was either a possible market or regulatory failure, or potential for efficiency gains focused on the possible inefficiencies in the status quo arrangements.
25. Under the current TPM, the HVDC costs are charged to all grid-connection South Island (SI) generation plant with an allocation proportional to peak generation based on Historical Anytime Maximum Injection (HAMI).
26. These current arrangements create a number of possible unintended inefficiencies:
  - Generation investment inefficiency from delaying SI generation. The HVDC charge leads to a disincentive for investment in SI generation relative to North Island (NI) generation. This disincentive could lead to generation investment inefficiency if SI generation investments are delayed relative to otherwise equivalent or more expensive NI options.
  - Competition effects between SI generators resulting from the HVDC charge. The allocation mechanism for the HVDC costs would favour new generation investment in the SI by large incumbent SI generators relative to small incumbent generators or new entrants if those investments by the large incumbents are more likely to delay alternative NI rather than SI investments by competitors. If this arises, large incumbent SI generators increase their dominance in the SI with consequential impacts on reduced competition in generation and retail.
  - Generation investment and dispatch inefficiencies from the HAMI price structure. The HAMI allocation provides disincentives to generators to offer peak capacity and invest in or maintain peaking generation capacity.
27. The TPAG has undertaken analysis of these potential inefficiencies and concluded that there is sufficient evidence of potential efficiency gains to warrant analysis of alternative TPM options.
28. The TPAG assessed five options against the six efficiency considerations. The five options are:
  - HVDC capacity rights.
  - MWh allocation to SI generators (rather than the status quo HAMI allocation).
  - An 'incentive-free' allocation to SI generators.
  - Postage stamping the HVDC costs to offtake.
  - A postage stamp transition option whereby the HVDC costs are eventually allocated to offtake but incorporating a transitional allocation to existing SI generators.
29. These options are drawn from the stage 2 consultation, submitters' suggestions and the TPAG's own considerations. There are variants of each of these options. Whilst the TPAG has not considered each variant separately, it has considered how the choice of variant might influence the analysis.

## HVDC options assessment summary

30. The TPAG's assessment is based on the Authority's assessment process and ultimately, the first question the Authority will need to address is whether there is a potential change to the TPM which would result in an efficiency gain for the long term benefit of consumers.
31. As noted in paragraph 27, the TPAG concluded early in its analysis that there was sufficient evidence of potential efficiency gains to warrant analysis of alternative options for the allocation of HVDC costs. The TPAG members did not agree as to whether there was sufficient evidence to justify a change from the status quo.
32. In the view of the minority, the efficiency gains are not material enough to justify a change from the status quo. The gains rely on some cheaper SI generation investment being brought forward ahead of more expensive NI generation as a result of the removal of the HVDC charge from grid-connected SI generators. According to the minority, this may not happen if other factors override the impact of the HVDC charge.
33. In the view of the majority, there is a clearly identified opportunity for efficiency gains for the long term benefit of consumers. The proposition is that the status quo arrangements whereby the grid-connected SI generators pay for the HVDC leads to inefficiencies in generation investment, peaker investment and dispatch leading to higher end prices to consumers. Once implementation and operating costs of alternative options are taken into account the possible efficiency gains from the alternative options with the greatest efficiency gains lie in the range \$11m to \$96m NPV.
34. As the majority view is that there is justification to change from the status quo, the Discussion Paper includes a majority view on the comparison of the costs and benefits of the options in order to identify a preferred option (CAP 3).
35. In the view of the majority, the assessment of the options suggests that:
  - the efficiency gains are greatest from applying either the postage stamp or postage stamp transition;
  - the likelihood of capturing the efficiency gains from either the postage stamp or postage stamp transition is equivalent to the likelihood of capturing the benefits under MWh;
  - postage stamping is likely to create an efficiency gain but it results in a significant immediate and certain transfer of value to SI generators offset by future and uncertain wholesale price effects;
  - as for postage stamping, the postage stamp transition option is likely to create an efficiency gain, but does not involve the immediate wealth transfers. This option appears to have the highest combined net benefit of all the options – it will provide efficiency gains with the least likelihood of dis-benefits to consumers.
36. Given that a transition to postage stamp is the majority preferred option, the TPAG has considered the design of transition options.
37. The transition could be implemented by requiring existing grid-connected SI generation plant to continue paying for a portion of the HVDC costs over a transition period and to have the remaining costs recovered via postage stamp charges to customers. The portion recovered from grid-connected SI generators would be phased out over a transitional period and the

allocation between existing generators would be fixed in advance so as to remove any incentives that could distort behaviour and create inefficiencies.

38. The postage stamp transition should remove the generation investment and dispatch inefficiencies associated with the status quo without creating significant wealth transfers.
39. The majority of the TPAG members agreed that an appropriate postage stamp transition would be achieved through a declining 'incentive free' charge grid-connected SI generators beginning at \$30/kW over a 10 year transition period.

### Assessing options for deeper or shallower connection

40. The TPAG does not make firm recommendations in its consideration of options for deeper or shallower connection, or for a deeper allocation of interconnection costs to specific customers. This is because the TPAG's ability to analyse the alternative options is limited by interactions with the regulatory role of the Commerce Commission. The TPAG concludes that progressing this work further requires close coordination with the Commerce Commission.
41. The TPAG's analysis of the options for deeper or shallower connection is intended to provide support for the Authority if and when it progresses these issues.
42. The TPAG's analysis of the status quo arrangements to establish whether there was either a possible market or regulatory failure, or potential for efficiency gains (CAP 2), focused on the possible efficiency gains that alternative options might yield.
43. Currently the TPM separates the grid into connection, interconnection and HVDC assets. The definition of connection is considered deep as it includes assets beyond those at the point of connection.
44. There may be efficiency gains from providing incentives to participants to take action to defer or avoid transmission investment where there are benefits from doing so. Providing a deeper definition of connection or allocating a deeper portion of interconnection costs directly to participants is a way of providing these incentives.
45. The potential benefits from deeper connection options arise from deferring new, uncommitted reliability investments. The TPAG reconsidered assessments of the possible benefits made by the Commission during stage 2 of the Review. The TPAG's high-level estimate of the possible benefits is \$15m to \$40m NPV, noting that implementation and operational costs have not been taken into account. The level of these benefits depends on the effectiveness of the transmission alternatives regime and the transmission investment approval process.
46. There may also be some benefits from adopting a shallower connection definition, as this may avoid the costs associated with parties lobbying Transpower to investigate alternatives to deep connection investments for which the costs will be recovered through interconnection costs.
47. The TPAG identified the following options for assessment relative to the status quo:
  - A shallower connection definition.

- A flow tracing approach which allocates shares of transmission assets to loads based on which customers 'use' the assets. Flow tracing would involve a cut-off threshold which defines the boundary between allocated and postage stamped interconnection assets.
  - A 'but-for' approach which involves a one-off identification of the beneficiaries of new deep connection assets when they are approved under the grid investment process.
48. The TPAG assessed these options against the six efficiency considerations relative to the status quo.

### Assessment summary for deeper or shallower connection options

49. Although the TPAG did not reach a firm conclusion on whether there is a clear efficiency gain to justify a change from the status quo its key findings are:
- The 'but-for' approach is likely to offer the greatest potential benefits in terms of deferring new reliability investment but the benefits may not be certain, it is likely to be costly to apply, it could give rise to contentious on-going issues with its application and it could involve significant wealth transfers.
  - The flow tracing approach should be simpler and less contentious to operate over time but the participant benefits are not always proportional to their use and price impacts and wealth transfers would be more widespread.
  - More evidence of significant problems would be required to justify a move to a shallow definition of connection.

### Assessing options for static reactive compensation

50. SRC refers to sources of reactive power that provide local voltage support and increase power transfer limits into regions that are subject to voltage instability.
51. The TPAG's analysis of the current treatment of SRC in order to establish whether there was either a possible market or regulatory failure, or potential for efficiency gains focuses on a potential regulatory failure.
52. Status quo arrangements rely on a power factor standard in the Connection Code to determine the allocation of costs for SRC. The power factor requirement for the Upper North Island (UNI) and Upper South Island (USI) is unity; and for the Lower North Island (LNI) and the Lower South Island (LSI) is 0.95. This is problematic for two reasons: it is not possible to comply with the requirement for unity power factor in the UNI and USI; and enforcement arrangements through transmission agreements are practically difficult.
53. In the TPAG's view the status quo arrangements have led to a regulatory failure that, if not remedied, may lead to inefficiencies in the way investments in SRC equipment are made.
54. The TPAG reviews the options for the treatment of SRC that were proposed in the stage 2 consultation paper and identifies an additional option. Two options are taken forward for assessing against the efficiency considerations: an amended status quo which involves a unity or leading power factor requirement for the UNI and USI and a form of kvar charging which will provide a price signal to enable offtake customers to make efficient choices to take steps to improve power factor or invest in SRC.

55. In the TPAG's view the amended kvar charge option has the highest net benefit relative to the status quo. This option would involve introducing a kvar charge, removing the power factor requirement in the Connection Code and introducing a penalty charge for reactive power at peak periods where the power factor falls below 0.95 lagging. The paper includes possible changes to the Connection Code and the TPM for SRC.
56. These changes are proposed for the UNI and USI regions only. The TPAG makes some additional comment on issues around consistency over the whole grid, and suggests that the amended kvar charge, suitably modified could be applied nationwide.

### **Conclusions and Draft Guidelines**

57. The TPAG has reached a number of conclusions some of which, if recommended to the Authority and the Authority accepts, would lead to the release of an Issues Paper and Draft Guidelines in accordance with Part 12 of the Code. Indicative Draft Guidelines are set out reflecting these conclusions.

## 1 Introduction

### 1.1 The Transmission Pricing Advisory Group (TPAG)

- 1.1.1 The Electricity Authority<sup>1</sup> (Authority) is continuing the Transmission Pricing Review (Review) initiated by the Electricity Commission (Commission) in early 2009 to undertake a wide-ranging review of options for the allocation methodology for transmission costs.
- 1.1.2 The Authority formed the Transmission Pricing Advisory Group (TPAG) to assist with the Review. The TPAG is tasked with providing independent advice to the Authority on a recommended option for the Transmission Pricing Methodology (TPM) and associated Guidelines if a change from the status quo is the preferred option.
- 1.1.3 The TPAG members were appointed by the Authority following a call for nominations in January 2011. The membership is set out in Table 1.

**Table 1 The TPAG membership**

Member	Nominating body
Graham Scott (chairperson)	-
John Clarke	Transpower
Glenn Sullivan	Fonterra
Bruce Girdwood	Vector
Ray Deacon	RTANZ
John Woods	Contact
Bob Weir	Genesis
Guy Waipara	Meridian
Peter Calderwood	TrustPower
David Reeve	Mighty River Power

- 1.1.4 The Authority established the TPAG in accordance with the Electricity Industry Act 2010 (Act) and the Authority's Charter about Advisory Groups<sup>2</sup>. The TPAG terms of reference<sup>3</sup> set out the role of the TPAG, the scope of the advice sought, and further details of the TPAG's governance and operations.

### 1.2 Purpose

- 1.2.1 A key aspect of the TPAG role is to publish a discussion paper for consultation, which provides, with supporting analysis, a preferred TPM option and associated Guidelines, where there is a

<sup>1</sup> The Electricity Authority succeeded the Electricity Commission on 1 November 2010.

<sup>2</sup> Available at: <http://www.ea.govt.nz/document/12289/download/our-work/advisory-working-groups/tpag/>

<sup>3</sup> Available at: <http://www.ea.govt.nz/document/12747/download/our-work/advisory-working-groups/tpag/>



change from the status quo, for the development of a TPM by Transpower. This paper is the TPAG's Discussion Paper, the purpose of which is to invite submissions on the TPAG's analysis and proposed recommendations.

### **1.3 Moving forward - Review process and timetable**

- 1.3.1 Following its consideration of submissions on this Discussion Paper, the TPAG is required to make its final recommendations to the Authority Board. If the TPAG's recommendation is for an alternative methodology and the recommendation is accepted by the Authority Board, the Authority will publish an Issues Paper including Draft Guidelines and Process for development of the TPM as required under the Electricity Industry Participation Code (Code)<sup>4</sup>. In accordance with Subpart 4 of Part 12 of the Code the Authority sets Guidelines for the development of the TPM, Transpower develops the TPM in accordance with the Guidelines and the Authority then makes a determination on the TPM.
- 1.3.2 The TPAG is undertaking its work as a matter of urgency, and, although consultation on the TPAG's Discussion Paper was not part of the Review's original work plan, the intention is to maintain a timeline for the Review that would enable implementation of any changes to the TPM for the pricing year starting 1 April 2013<sup>5</sup>.
- 1.3.3 Table 2 sets out:
- a) the TPAG's work following the publication of this Discussion Paper;
  - b) the Code-prescribed processes that will follow if the Authority determines that a new TPM is justified, including details of any Code-prescribed timeframes; and
  - c) other work required in order to implement and apply any new TPM.
- 1.3.4 Table 2 also provides indicative dates.

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<sup>4</sup> Refer clause 12.81 to 12.83 of the Code.

<sup>5</sup> The application of the TPM is an annual process. For prices to be effective from 1 April in any given year, Transpower begins its pricing process (including calculating and auditing prices) by August of the preceding year. Transmission agreements require Transpower to provide prices by 31 December of the preceding year for application on 1 April. Transpower seeks to provide prices before this date to assist participants.

Table 2 Review process with indicative dates

	Detail	Relevant Code provisions	Indicative timeframe
The TPAG process	The TPAG discussion paper submissions deadline		Mid-July
	The TPAG recommendation to Authority Board		Mid-August
Code-prescribed process	Issues Paper and Draft Guidelines and Process, published for consultation	12.81 to 12.83	Mid-September 2 months
	<b>TPM development</b> Authority publishes Guidelines and Process and requests new TPM. Transpower submits a TPM within <b>90 days</b> of request, including indicative prices.	12.88,12.89	4 months
	<b>TPM determination</b> Authority: <ul style="list-style-type: none"> <li>• may decline to consider the TPM</li> <li>• approves or refers back or amends</li> <li>• publishes proposed TPM for consultation</li> <li>• makes determination on TPM</li> <li>• TPM gazetted, becomes a schedule to the Code</li> </ul>	12.90 to 12.94	4 -5 months <i>Note: More time may be needed if the TPM is referred back to Transpower</i>
(Not a Code-prescribed process)	<b>Transpower implementation</b> This is the time Transpower requires for implementing a new TPM and will depend on the complexity of the preferred option. Transpower provided initial estimates for some options from stage 2 of the Review.	Estimated timeframe of up to two years, depending on the nature and complexity of the option adopted and the implementation approach	
Code-prescribed process	<b>TPM application</b> Transpower develops and publishes transmission prices consistent with the TPM and the Authority may appoint an auditor to confirm whether prices have been correctly calculated.	12.96 to 12.101	Start Aug of year preceding pricing year
Transmission agreements	<b>Transpower to provide prices to customers by 31 December of the year preceding the pricing year.</b>	Clause 41.5 Benchmark Agreement	By 31 December of year preceding pricing year

1.3.5 As can be seen, the timeframes are very tight if there are to be changes to the TPM in place for April 2013. There are several key assumptions underpinning the indicative timeframes presented here. In particular:

- the TPM determination is straightforward and does not require referral back to Transpower;

- any changes do not require more time to develop by Transpower than the 90 days set out in the Code; and/or
- Transpower is willing to undertake some implementation in parallel to other processes, or is able to reduce implementation times.

#### 1.4 Submissions

- 1.4.1 This consultation paper is published by the TPAG. Although the TPAG will be responsible for considering the submissions, the Authority will receive submissions on the TPAG's behalf.
- 1.4.2 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](mailto:submissions@ea.govt.nz) with "TPAG Transmission Pricing Discussion Paper" in the subject line.
- 1.4.3 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.
- |  |           |   |
|--|-----------|---|
| <p>Submissions<br/>TPAG Chair<br/>c/- Electricity Authority<br/>PO Box 10041<br/>Wellington 6143</p> | <p>or</p> | <p>Submissions<br/>TPAG Chair<br/>c/-Electricity Authority<br/>Level 7, ASB Bank Tower<br/>2 Hunter Street<br/>Wellington</p> |
|--|-----------|---|
- Tel: 0-4-460 8860  
Fax: 0-4-460 8879
- 1.4.4 Submissions should be received by 5.00 pm on 14 July 2011 Please note that late submissions are unlikely to be considered.
- 1.4.5 The Authority, on behalf of the TPAG, 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.
- 1.4.6 If possible, submissions should include responses to the questions the TPAG has included in the Discussion Paper. The full list of questions is given in Appendix A.
- 1.4.7 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 TPAG on a confidential basis. However, all information provided to the TPAG is subject to the Official Information Act 1982.

## 2 Background

### 2.1 Transmission pricing in New Zealand

- 2.1.1 Transpower's total transmission revenue requirement is regulated by the Commerce Commission. The TPM is a regulated methodology that determines how Transpower's total revenue is allocated between, and recovered from, its customers.
- 2.1.2 The level and structure of transmission charges under the TPM have the potential to influence the use of the network, operation of and investment in the electricity market. For example, transmission charges can influence the locational choices of generators and their bidding behaviour. The challenge is to allocate transmission costs in a way that encourages:
- a) efficient use of the transmission network and operation of the electricity market in real time; and
  - b) efficient investment in new load and generation projects (including load management), which will influence future demand on the transmission network and the need for transmission investment.
- 2.1.3 The current TPM is based, with some refinements, on the TPM that was developed by Transpower and first applicable from 1 April 1999. The 1999 TPM represented a shift from the previous methodologies used by Transpower to allocate transmission costs. One of the key differences from earlier approaches was the introduction of three distinct charges: connection charges, interconnection charges and explicit High Voltage Direct Current (HVDC) charges for grid-connected South Island (SI) generators only. The current TPM took effect on 1 April 2008 and is comprised of these three charges, but has introduced further refinements. These include a change to the allocation of interconnection charges according to the customer's share of the Regional Coincident Peak Demand (RCPD), and a deeper definition of connection assets.

### 2.2 The transmission pricing review

- 2.2.1 During the development of the current TPM the Commission considered whether to conduct a more comprehensive review of transmission pricing including whether enhanced locational signals to generation and load may be efficient. However, ultimately the Commission decided that it was preferable to implement a methodology in the short term and noted that a review was intended in the future.
- 2.2.2 The rationale at the time was that nodal pricing, the approval of transmission investment under the Grid Investment Test (GIT) and a definition of deep connection may be sufficient with respect to locational signalling. The Commission acknowledged that further analysis was required to confirm this, but in the meantime considered it was prudent to postage stamp the costs of providing interconnection assets. The final approach differed in respect of the HVDC link. This proved to be a controversial decision and, following the determination of the TPM, parties requested that the Commission undertake a further review of the HVDC charge. The Commission noted that any future review should be "holistic, focusing on locational pricing", rather than merely focussing on allocating the costs of the HVDC link.
- 2.2.3 Against this background the Commission initiated the Review in April 2009 to undertake a wide-ranging review of options for the allocation methodology for transmission costs. The Authority is continuing with the Review.

## 2.3 Related work streams

- 2.3.1 There are a number of related and parallel work streams which may impact on the Review process, depending on the outputs of those work streams and their relevance to the Review findings. The Commission, the Authority and the TPAG have as far as possible sought to align the Review process with the approaches taken in related work streams to ensure coherent market and regulatory development. The following work streams are particularly relevant:
- a) **The Authority's locational hedging project.** A consultation paper on the Code development for the introduction of an inter-island Financial Transmission Right (FTR) was published in April 2011<sup>6</sup>. Participants have indicated that having an understanding of the preferred options for transmission pricing is a significant issue for understanding the implications of a locational hedging proposal. This is particularly the case for the pricing for the HVDC link. The Act requires that Code amendments on this matter are finalised by 1 November 2011<sup>7</sup>. The development of the locational price risk is also linked to the proposed introduction of scarcity pricing.
  - b) **The Authority's scarcity pricing project.** This project is designed to address concerns that spot prices are likely to be suppressed when non-price mechanisms (such as requests for voluntary conservation by consumers) are used to curtail demand. It is important during supply emergencies that spot prices provide efficient signals, otherwise efficient investment in last resort generation and/or voluntary demand-side response will be undermined. In March 2011 the Authority published a consultation paper<sup>8</sup> setting out its proposed set of scarcity pricing measures designed to induce higher levels of generation and/or price responsive demand. As for locational hedging, Code amendments for scarcity pricing need to be completed by 1 November 2011.
  - c) **The Commerce Commission's Transmission Capital Expenditure Input Methodology.** The final input methodology determinations for Transpower, lines companies and other relevant sectors were published on 23 December 2010<sup>9</sup>. In addition to these input methodologies, the Commerce Commission is also required to determine an input methodology for Transpower's capital expenditure proposals (Capex IM). This input methodology will include the grid investment approval process and as part of this, the process for consideration of transmission alternatives. The Capex IM must be determined no later than 1 November 2011, but the Minister of Commerce may, on the written request of the Commerce Commission, extend the deadline once by a period of up to three months. The Commerce Commission has released its notice of intention to advise that it has begun work on the Capex IM and its preliminary views on Capex IM. It is due to publish its Draft Determination in June/July 2011.
- 2.3.2 Where relevant, the implications of these workstreams for transmission pricing are considered in this discussion paper.

<sup>6</sup> Available at: <http://www.ea.govt.nz/our-work/consultations/priority-projects/lpr-proposed-amendments/>.

<sup>7</sup> There is an ability for the Authority to postpone addressing these issues within the timeframe outlined above. Section 42 of the Act provides that the Authority can provide a report to the Minister if any of the new matters required to be addressed (including locational price risk management and scarcity pricing) are not addressed within the prescribed timeframes. According to section 42(3), this report must identify those matters, explain why they have not been addressed, suggest alternative methods to address them and set out if, when and how the Authority proposes to address them. The Authority is however working towards meeting the timeframes set out in the Act.

<sup>8</sup> Available at: <http://www.ea.govt.nz/our-work/consultations/priority-projects/scarcity-pricing-arrangements-proposed-design/>.

<sup>9</sup> Available at: <http://www.comcom.govt.nz/input-methodologies-2/>. Note these determinations are subject to appeal.

- 2.3.3 There is a particular linkage between transmission pricing and the development of an inter-island FTR. Currently loss and constraint excess payments (rentals) are allocated to transmission customers under Transpower's loss and constraint excess allocation methodology<sup>10</sup>. This methodology allocates rentals for specific asset classes (connection, interconnection and HVDC) to those customers who pay for the assets. Under this methodology the HVDC rentals are allocated to grid-connected SI generators. If an inter-island FTR is implemented the associated rentals would be allocated to purchasers of the FTR. For this reason, the analysis in this paper on options for the allocation of HVDC costs considers the impact on the analysis if SI generators no longer receive the equivalent value of the HVDC rentals.
- 2.3.4 The inter-island FTR is likely to generate surplus revenue including FTR auction proceeds (FTR residual revenue). The Authority is undertaking work to determine how residual FTR revenue should be allocated, and the TPAG will need to consider the implications of different treatments of rentals and FTR residual revenue as this work progresses.

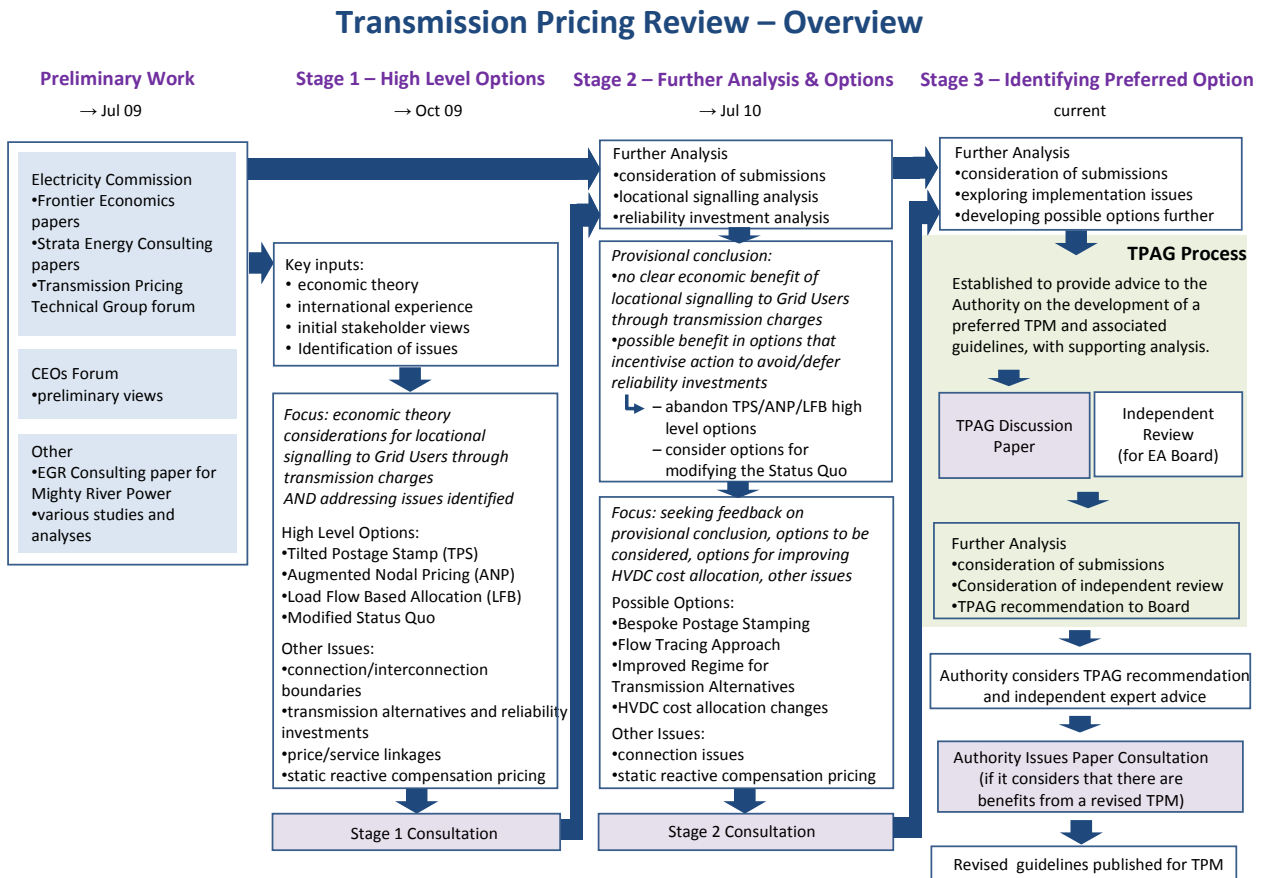
## 2.4 Overview of the Review to date

- 2.4.1 The Commission established the Review as a three stage project and undertook the first two stages, each culminating in a consultation paper. The Authority took responsibility of the Review from 1 November 2010 following the publication of the second consultation paper and is undertaking the third stage of the Review: the identification of a preferred option for the TPM.
- 2.4.2 This section provides a high level summary of the analysis, submitters' views and outcomes from earlier stages of the Review. It also summarises the TPAG's consideration of analysis undertaken as part of stage 2 on the benefits of locational signalling for economic transmission investments. This analysis is pivotal to the direction of the Review and the subsequent work of the TPAG.
- 2.4.3 A pictorial representation of the Review is set out in the figure 1, and described in more detail below.

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<sup>10</sup> Available at: <http://www.transpower.co.nz/f1491,934892/transmission-rentals-2008.pdf>

Figure 1 Overview of Review



## 2.5 Preliminary work

2.5.1 The Review commenced in April 2009. The Commission and a number of stakeholders undertook analysis and engaged advisers in the lead up to the stage 1 consultation. The Commission established the Transmission Pricing Technical Group (TPTG) made up of technical specialists nominated by interested parties. For the purposes of this overview, this has been grouped as Preliminary Work, although some of it relates to the period before the Review was initiated, and some of it continued in parallel with stage 1 of the Review. All of the papers are available on the Authority's website<sup>11</sup>.

2.5.2 NERA was engaged by the NZ Electricity Industry Steering Group (established by the CEOs Forum) to explore ways in which to improve the efficiency of electricity transmission pricing arrangements in the NZ market. The CEOs Forum provided preliminary views to the Commission during this time, with the formal NERA Report submitted shortly after the stage 1 consultation process.

## 2.6 Stage 1 – high level options (to October 2009 consultation)

2.6.1 The preliminary work described above provided key inputs to the Commission's work in identifying the high level options and other issues to be addressed in the Review process.

<sup>11</sup> <http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/>.

- 2.6.2 It also helped to frame the focus for the first stage of the Review: that economic theory considerations were primary and that particular consideration needed to be given to whether there was sufficient justification to consider enhanced locational signalling in addition to that provided by nodal pricing, deep connection and the grid investment test.
- 2.6.3 The Commission analysis and thinking was set out in its Stage 1 Consultation Paper<sup>12</sup>. This was drawn from the key inputs described above, and further informed by the Commission's own analysis, feedback from the TPTG and a further paper prepared by Frontier Economics "Identification of High Level Options and Filtering Criteria"<sup>13</sup>.
- 2.6.4 The high level options included in the Stage 1 Consultation Paper were:
- a) **Status Quo** – the current transmission pricing arrangements were included as a high-level option. The stage 1 consultation paper also asked submitters if there were possible minor modifications that could be made to the current arrangements.
  - b) **Tilted Postage Stamp (TPS)** – this approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing comparatively higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.
  - c) **Augmented Nodal Pricing** – this approach seeks to directly address possible deficiencies in nodal energy prices. Under this regime: transmission charges should be highest for those generators and loads that benefit most from theoretically premature network investment; and transmission charges should be lowest for those generators and loads that benefit least off from theoretically premature network investment.
  - d) **Load Flow Based Allocation** – these options involve a process of network analysis to attribute costs to participant connection points based on identification of the network assets used to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (cost reflective network pricing (CRNP)) or on forward-looking network development costs, as in Great Britain (investment cost related pricing (ICRP)).
- 2.6.5 The Stage 1 Consultation Paper also identified four other issues to be addressed by the Review:
- the approach to setting connection charges;
  - the treatment of transmission alternatives;
  - linking transmission pricing with service quality; and
  - static reactive power compensation.

## 2.7 Stage 2 – further analysis and options (to July 2010 consultation)

- 2.7.1 Nineteen parties from across the electricity sector provided submissions on the Stage 1 Consultation Paper, as set out in Table 3. At this time the Commission also received final reports and analysis from the CEOs Forum including analysis from Transpower, and New Zealand Institute

<sup>12</sup> Available at <http://www.ea.govt.nz/our-work/consultations/transmission/tpr/>.

<sup>13</sup> Also available at: <http://www.ea.govt.nz/our-work/consultations/transmission/tpr/>.



of Economic Research (NZIER) reports on behalf of the Major Electricity Users' Group (MEUG) and Rio Tinto.

- a) **CEOs Forum input:** NERA<sup>14</sup> considered that many features of the existing transmission pricing arrangements were fundamentally sound, but there were some potential problems (including issues relating to Long Run Marginal Cost (LRMC) signalling, the GIT, HVDC charging, and deep connection). NERA considered a number of possible options for reform including introducing further locational signals (eg through a TPS approach), modifying the HVDC charging regime, and some relatively modest amendments to connection charge arrangements.
- b) **Transpower work:** Transpower<sup>15</sup> undertook analysis at the request of the CEOs Forum working group to determine whether there is an enduring grid characterisation that might support the introduction of a TPS pricing methodology and to assess the potential impact of a TPS on total costs.
- c) **NZIER:** NZIER was commissioned to undertake work for Rio Tinto and for the MEUG as input to the CEOs Forum and to the Commission's Review. NZIER completed three reports:
  - 'New Zealand Transmission Pricing Project – A Review of the NERA report to the Electricity Industry Steering Group'<sup>16</sup>. This report was critical of NERAs analysis and of the basis for the NERA options.
  - 'Alternative Options for Transmission Pricing – Suggestions for the Review by the CEOs Forum'<sup>17</sup>. This report suggested a capacity rights or arbitrageur approach for the HVDC link and a deeper connection regime for charging for new assets (also known as 'but-for').
  - Competitive Neutrality for Connection of Generation<sup>18</sup>. This report contained a discussion about the TPM on generators decisions on where to connect.

**Table 3 Submissions received on Stage 1 Consultation Paper**

Generator/retailer	Large user	Distributor	Other
Contact	Business New Zealand	Counties Power	Transpower
Genesis	Major Energy Users' Group (MEUG)	Northpower	Electricity Efficiency and Conservation Authority (EECA)
Meridian	Norske Skog	Orion	
Mighty River Power (MRP)	Pan Pac	Powerco	
Todd Energy (late submission)	Rio Tinto	Vector	
	Winstone Pulp International	Electricity Networks Association (ENA)	

<sup>14</sup> NERA report for the CEO Forum is available at: <http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/>

<sup>15</sup> <http://www.ea.govt.nz/document/13792/download/our-work/programmes/priority-projects/transmission-pricing-review/>

<sup>16</sup> Available at: <http://www.ea.govt.nz/document/4561/download/our-work/consultations/transmission/tpr/submissions/>

<sup>17</sup> Available at: <http://www.ea.govt.nz/document/4562/download/our-work/consultations/transmission/tpr/submissions/>

<sup>18</sup> Available at: <http://www.ea.govt.nz/document/4563/download/our-work/consultations/transmission/tpr/submissions/>

- 2.7.2 Views were mixed, and no clear preference emerged from the consultation process. Some submitters supported a TPS approach, some preferred the status quo or a modified status quo, and some proposed alternative options for the Commission to consider. The Commission published an initial summary of submissions in March 2010<sup>19</sup>.
- 2.7.3 In parallel with its consideration of submissions, the Commission:
- reconsidered the economic theory arguments for further locational signalling to generation and load to encourage co-optimisation of investment in generation, load and transmission;
  - undertook significant modelling and analysis work using its Generation Expansion Model (GEM) to consider the potential benefits of further locational signalling to generation and load from the perspective of signalling in respect of future economic transmission investments; and
  - considered the potential benefits of deferral of future reliability transmission investments.
- 2.7.4 Drawing from this work and its consideration of stage 1 submissions, the Stage 2 Consultation Paper<sup>20</sup> signalled two important provisional conclusions:
- there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments; and
  - there appears to be a possible benefit in options that incentivise action to avoid or defer reliability-driven investments (eg through investment in generation and/or load management).
- 2.7.5 A key implication of the provisional conclusions, as noted in the Stage 2 Consultation Paper, was that there would be no merit in pursuing the three high level transmission pricing options aimed at enhancing locational signals for economically-driven transmission investments, i.e. TPS, augmented nodal pricing, and load flow based allocation. Instead the Review should focus on options for modifying the status quo that might incentivise action to defer reliability-driven investments, options for HVDC charging, and addressing the other key issues identified. This framed the remainder of the stage 2 work.
- 2.7.6 The Stage 2 Consultation Paper identified the following options to incentivise the deferral of reliability investments, and sought submitters' views on each, noting that they were not mutually exclusive and could be implemented in some combination:
- a) Bespoke postage stamping option involving a higher charge on loads and credits to generators in particular regions. This is intended to provide localised signals for additional peaking plant and demand response in areas likely to require reliability transmission investment in the medium term, perhaps based on the use of an LRMC approach to determining locational charges.
  - b) Flow tracing approach to allocating the costs of a portion of interconnection assets to specified parties, possibly coinciding with a shallower approach to defining connection assets.

<sup>19</sup> Available at: <http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/>.

<sup>20</sup> Available at: <http://www.ea.govt.nz/our-work/consultations/transmission/tpr-stage2options/>.

- c) Improving the transmission alternatives regime – particularly by avoiding the perception of competing interests faced by Transpower as both the network owner and the party responsible for the tender process and assessment of alternatives against transmission options.

2.7.7 The paper also set out a number of options for HVDC charging, and sought comments on each:

- a) status quo;
- b) continue to charge grid-connected SI generation plant, but with an allocation proportional to generation in MWh rather than based on Historical Anytime Maximum Injection (HAMI);
- c) continue to charge grid-connected SI generation plant, but with an incentive-free allocation, perhaps based on historical output; and
- d) postage stamp – spread costs widely over offtake and/or generation in both islands.

2.7.8 Finally, the paper addressed the other issues from the Stage 1 Consultation Paper, and considered two of the issues should be progressed further in the context of the Review:

- a) connection issues; and
- b) static reactive compensation.

The decision was made not to continue the investigation of the link between price and service within the context of the Review. The consideration of possible improvements to the transmission alternatives regime was continued through the work on incentivising deferral of reliability investments above.

The Stage 2 Consultation Paper, including the appendices, and the submissions on it, provide a basis for the stage 3 work the Authority, and the TPAG, are now embarking on.

## 2.8 Stage 3 (current)

2.8.1 The Authority is continuing the final stage of the Review and has appointed the TPAG to make recommendations on a preferred TPM option. This stage of the Review includes review of submissions on the Stage 2 Consultation Paper and further analysis of options in order to identify a TPM preferred option.

2.8.2 Eighteen parties from across the electricity sector provided submissions on the Stage 2 Consultation Paper, as set out in Table 4.

**Table 4 Submissions received on Stage 2 Consultation Paper**

Generator/retailer	Users	Distributor	Other
Contact	Business New Zealand	WEL Networks	Transpower
Genesis	MEUG	Northpower	Electricity Efficiency and Conservation Authority (EECA)
Meridian	Norske Skog	Powerco	Opuha Water
Mighty River Power (MRP)	RTANZ	Vector	
Todd Energy		Electricity Networks Association (ENA)	
Trustpower			

2.8.3 Submitters' views on key matters set out in the Stage 2 Consultation Paper are briefly summarised in Table 5.

**Table 5 Brief summary of submissions on Stage 2 Consultation Paper**

Issue	Overall comment
Stage 2 analysis	<p>Submitters generally concurred with the economic theory analysis that the Commission presented in the consultation paper, agreeing that the consultation paper had identified the relevant factors in its assessment of whether nodal pricing, the grid investment test and deep connection provide adequate signals for efficient generation and load investment.</p> <p>A minority of submitters questioned the Commission's modelling for assessing the benefits of locational signalling for economic transmission investments on the basis that the modelling was highly dependent on the input assumptions and that the use of the GEM may not have been appropriate. Despite these concerns most submitters agreed with the results: that there is limited value in signalling economic transmission investments.</p> <p>Submitters challenged the analysis of the potential benefits of signalling reliability investments more strongly.</p>
Stage 2 Options	<p>The Commission had set out its decision not to pursue some high level options described during stage 1 of the Review or previously suggested by submitters. Submitters generally supported the Commission decision not to further consider augmented nodal pricing and TPS. Three large user representatives considered that the Commission should undertake further analysis on the 'but-for' approach and the capacity rights option suggested for the HVDC link.</p> <p>Submitters were divided on the benefits of the incentives for deferring reliability investments, and gave arguments both for and against the three options suggested: bespoke pricing, flow tracing and improving the transmission alternatives regime.</p>
HVDC Options	<p>The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs.</p> <p>The three largest SI generators all favoured postage stamping the HVDC costs. Large user representatives supported further consideration of an alternative option – capacity rights, as a means of allocating costs to beneficiaries. Transpower considered that there appears to be a reasonable case for retaining the charge, but allocating it based on MWh. Meridian and Todd Energy suggested allocating the charge according to flows across the link.</p> <p>Two submitters considered the existing charging is well-founded there is no need to consider the efficiency implications of the charge any further.</p>
Further Issues	<p>Submitters commented on arrangements for independently provided connection assets. Some have suggested that, although parties should in principle be able to mutually-negotiate shared arrangements for new connection assets, in practice there is a need for intervention as a backstop. Submitters have also raised other issues in relation to connection arrangements.</p> <p>Of the three options presented for the treatment of SRC, submitters generally favoured either connection asset definition or kvar charging. Transpower presented an alternative variant of kvar charging. There were strong views against the status quo and amended status quo which rely on the terms of the Connection Code.</p>

- 2.8.4 The TPAG's scope of work includes reviewing and commenting on the Stage 2 Consultation Paper submissions. Where relevant, this Discussion Paper refers to submitters' comments and considers them as part of the analysis. Appendix B provides a summary of the relevant issues raised by submitters and the TPAG approach to considering them.

**The TPAG's consideration of stage 2 analysis of value of location-based price signals**

- 2.8.5 The conclusion that "there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision" and the GEM analysis that underpins it has been pivotal to the direction of the Review and the work of the TPAG. The TPAG therefore spent some time understanding and testing the assumptions underpinning GEM and the conclusions drawn from the GEM analysis. On the basis of its own deliberations, the work undertaken by the Commission and the Authority and the largely supportive submissions from participants, the TPAG has concluded that there is no justification in imposing additional transaction costs on the industry in order to introduce additional locational signals through transmission pricing for economic investments in transmission assets.
- 2.8.6 The basis for reaching this conclusion is set out in Appendix C.

**Q1.** Do you agree with the TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision? If not, please provide your reasons.

**The TPAG's analysis**

- 2.8.7 The remaining sections of this Discussion Paper describe the regulatory framework then set out the TPAG's analysis framework, scope of work and analysis of the options.

### 3 Regulatory context for the Review

- 3.1.1 This section briefly describes the regulatory context for the Review and outlines the regulatory and institutional changes that have occurred during the course of the Review.
- 3.1.2 The Commission commenced the Review under the jurisdiction of the Electricity Act 1992 but on 1 November 2010 the Commission was succeeded by the Authority as one of a number of sector changes introduced under the Electricity Industry Act 2010 (the Act). The Authority was established to oversee the administration and ongoing development of New Zealand's electricity market. Responsibility for the Review was transferred to the Authority.
- 3.1.3 The objective of the Authority, as set out in Section 15 of the Act, is:
- “ to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers<sup>21</sup>”
- 3.1.4 The Code<sup>22</sup> replaced the Electricity Governance Rules 2003 (Rules) and came into force on 1 November 2010. The Authority is required to make and administer the Code and to monitor compliance with the Act, regulations, and the Code. Although operating as an independent crown entity, the Authority is required to have regard to Government Policy Statements presented in Parliament by the Minister of Energy and Resources<sup>23</sup>.
- 3.1.5 The TPAG's recommendations must therefore be consistent with the Act and the Authority's statutory objective, and have regard to any Government Policy Statement or Statement of Government expectations in force at the time. The options must also be consistent with subpart 4 of Part 12 of the Code.

### 3.2 Decision making framework for the Review

- 3.2.1 The provisions in the Code relating to transmission pricing and the development of the TPM (subpart 4 of Part 12) were largely carried over from section IV of part F of the Rules. Pre 1 November 2010 the regulatory framework for the TPM was governed by the Electricity Act 1992 and the Rules. This required that the preferred option was:
- a) consistent with the Commission's principal objectives and specific outcomes set out in section 172N of the Electricity Act 1992<sup>24</sup>;
  - b) consistent with the relevant objectives and outcomes in the Government Policy Statement on Electricity Governance;
  - c) developed and approved in accordance with section IV of part F of the Rules. In particular this required that the TPM was consistent with the pricing principles set out in rule 2 of section IV of part F of the Rules; took into account practical considerations, transaction costs and the desirability for consistency and certainty for both consumers and the industry; and

<sup>21</sup> “Consumers” is defined in the Act as “any person who is supplied, or applies to be supplied, with electricity other than for resupply”. “Consumers” therefore refers to “electricity consumers”.

<sup>22</sup> The Code is largely based on the Electricity Governance Rules 2003, the Electricity Governance (Security of Supply) Regulations 2008 and the Electricity Governance (Connection of Distributed Generation) Regulations 2007.

<sup>23</sup> There is no current relevant Government Policy Statement.

<sup>24</sup> The Commission's principal objectives in section 172N of the Electricity Act 1992 required the Commission to:

- (a) Ensure that electricity is produced and delivered in an efficient, fair, reliable and environmentally sustainable manner; and
- (b) Promote and facilitate the efficient use of electricity.

d) consistent with any determination made under Part 4 of the Commerce Act 1986.

- 3.2.2 The establishment of the Authority with a new statutory objective led to a reconsideration of the decision framework that underpinned previous decisions about the TPM and in particular the ongoing relevance of the pricing principles. As part of a separate Review work stream, the Authority reviewed the ongoing relevance of the transmission pricing principles carried over to the Code. The Authority's analysis, supported by submissions from stage 2 of the Review, concluded that the interface between its statutory objective, the Guidelines and the pricing principles was complex and unwieldy and, combined with the ongoing lack of consensus around the pricing principles, was a demonstrable regulatory failure. On this basis the Authority initiated a Code amendment proposal to remove the pricing principles from the Code<sup>25</sup> and as a result the pricing principles were removed from the Code with effect from 1 June 2011.
- 3.2.3 With the removal of the pricing principles from the Code, Transpower's and the Authority's decision making regarding the TPM must be done with reference to the statutory objective. The analysis in this paper was carried out prior to 1 June 2011 but anticipates the removal of the pricing principles from the Code as the Authority had made and published its decision. It would have been unproductive to assess TPM options against criteria which will not be relevant by the time decisions are made.
- 3.2.4 The regulatory framework for the TPM post 1 June 2011 requires that the preferred option is:
- a) consistent with the Authority's statutory objective;
  - b) developed and approved in accordance with subpart 4 of part 12 of the Code;
  - c) consistent with any determination made under Part 4 of the Commerce Act 1986; and
  - d) developed having regard to any statements of government policy concerning the electricity industry issued by the Minister (noting again that there is currently no relevant government policy statement).
- 3.2.5 In addition because the TPM is a schedule to the Code, any proposal to amend the existing TPM must ultimately be progressed as a Code amendment. The Code amendment principles (CAPs) must therefore be applied. The relevance of the CAPs is discussed in more detail in 3.3.2. The CAPs are an important input to the TPAG's assessment framework.

### 3.3 The Authority's foundation documents

- 3.3.1 The Authority has three foundation documents which make key strategic statements as to how the Authority will approach its decision making and undertake its duties under the Act. These are summarised in Table 6 and are available in full from the Authority's website<sup>26</sup>. These documents are relevant to the Review, and to the TPAG's role. In particular, the analysis framework described in Section 4 of this paper draws heavily on these, and the TPAG work programme also acknowledges the Authority's policies regarding consultation and progressing Code amendments.

<sup>25</sup> The consultation and decision papers are available at: <http://www.ea.govt.nz/our-work/consultations/priority-projects/regulatory-framework-tpm/>

<sup>26</sup> Available from <http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/>

Table 6 The Authority's foundation documents

Foundation document	Purpose and content
Interpretation of the Authority's statutory objective	<p>The Interpretation of the Authority's statutory objective clarifies how the Authority interprets its statutory objective, will assist the Board to make consistent decisions, and will assist staff and advisory groups to develop Code amendments and market facilitation measures for the Board's consideration.</p> <p>The Authority interprets its statutory objective as requiring it to exercise its functions in section 16 of the Act in ways that, for the long-term benefit of electricity consumers:</p> <ul style="list-style-type: none"> <li>• facilitate or encourage increased competition in the markets for electricity and electricity-related services, taking into account long-term opportunities and incentives for efficient entry, exit, investment and innovation in those markets;</li> <li>• encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise the total costs whilst being robust to adverse events; and</li> <li>• increase the efficiency of the electricity industry, taking into account the transaction costs of market arrangements and the administration and compliance costs of regulation, and taking into account Commerce Act implications for the non-competitive parts of the electricity industry, particularly in regard to preserving efficient incentives for investment and innovation.</li> </ul>
Consultation Charter	<p>The Act requires the Authority to develop, issue, and make publicly available a consultation charter. This consultation charter must include guidelines, not inconsistent with the Act, relating to the processes for:</p> <p>(a) amending the Code; and</p> <p>(b) consulting on proposed amendments to the Code.</p> <p>For the sake of clarity, the Authority has divided the consultation charter into two parts:</p> <p>(a) Part 1 relates to processes for amending the Code; and</p> <p>(b) Part 2 relates to processes for consulting on proposed amendments to the Code.</p> <p>A key aspect of the Consultation Charter is the set of CAPs which are to be applied when considering options for amending the Code. The CAPs are relevant to the Review decision making because a revision to the TPM is a Code amendment. The CAPs are described in more detail below.</p>
Charter about Advisory Groups	<p>The Act requires the Authority to establish one or more advisory groups<sup>27</sup> to provide independent advice to the Authority on the development of the Code and on market facilitation.</p>

<sup>27</sup> The Act also requires the Authority to appoint an advisory group called the Security and Reliability Council to provide independent advice to the Authority on the performance of the electricity system and the system operator and reliability of supply issues.



Foundation document	Purpose and content
	<p>The Act requires the Authority to make, and make publicly available, a charter on:</p> <ul style="list-style-type: none"> <li>(a) how it will establish and interact with the advisory groups; and</li> <li>(b) when and how it will consult advisory groups on material changes to the Code; and</li> <li>(c) how advisory groups must operate, including provisions concerning procedure.</li> </ul>

### Code Amendment Principles

3.3.2 When considering amendments to the Code, the Authority and its advisory groups are required to have regard to the CAPs to the extent that they are considered to be applicable. Although the Guidelines are not part of the Code, the TPM is<sup>28</sup>, and the Guidelines will direct Transpower in its development of the TPM. The CAPs are therefore not directly applicable to the development of Guidelines but as both the Guidelines and the CAPs are relevant to the development and determination of a revised TPM, to ensure consistency from the earliest stages, the CAPs are an important aspect of the decision framework for the TPAG and the Authority in the development of the a preferred option and associated Guidelines.

3.3.3 The CAPS are intended to provide guidance about:

- the potential scope of the Code with regard to achieving the Authority’s statutory objective; and
- how the Authority and its advisory groups will consider Code amendment matters, particularly where quantitative Cost Benefit Analyses (CBAs) yield inconclusive results.

3.3.4 The following tables summarise the CAPs.

**Table 7 The Code amendment principles 1 to 3**

Principle		Key Points from Code Amendment Principles
1.	Lawfulness	<ul style="list-style-type: none"> <li>• Must be consistent with the Act and the Statutory Objective</li> </ul>
2.	Clearly Identified Efficiency Gain or Market or Regulatory Failure	<ul style="list-style-type: none"> <li>• Must be able to demonstrate an efficiency gain or a market or regulatory failure or problem with Code.</li> </ul>
3.	Quantitative Assessment	<ul style="list-style-type: none"> <li>• Quantitative CBA to assess long-term benefits</li> <li>• Competition and reliability effects are to be assessed within CBA framework</li> <li>• Dynamic efficiency is particularly important</li> <li>• Sensitivity analysis is required</li> </ul>

<sup>28</sup> The TPM is Schedule 12.4 of the Code, any amendments to the TPM will therefore be a Code amendment.

- 3.3.5 Principles 1-3 are the primary principles to be applied to the development of TPM Guidelines. In the event that the application of these primary principles is inconclusive about which is the best option a number of tie-breaker principles would be applied as follows.

**Table 8 Code amendment principles 4 to 9**

Tie Breaker Principle		Key Points from Code Amendment Principles
4.	Preference for Small-Scale Options	<ul style="list-style-type: none"> <li>• Favour small-scale trials</li> </ul>
5.	Preference for Competition	<ul style="list-style-type: none"> <li>• Prefer options that focus on competition to achieve efficiency gains</li> </ul>
6.	Preference for Market solutions	<ul style="list-style-type: none"> <li>• Prefer options that focus on efficient market-based structures</li> </ul>
7.	Preference for Opt-Out Features	<ul style="list-style-type: none"> <li>• Prefer options that give participants opt-out options, unless more restrictive options are justified on the grounds of non-rivalry and/or non-excludability.</li> </ul>
8.	Preference for Non-Prescriptive Options	<ul style="list-style-type: none"> <li>• Focus on options that specify outputs rather than inputs</li> </ul>
9.	Risk reporting	<ul style="list-style-type: none"> <li>• Final tie-breaker if CBA is inconclusive and principles 5-8 do not discriminate</li> <li>• Report required to assess risks of proceeding or not proceeding with option</li> </ul>

### 3.4 Impact of regulatory change on work undertaken to date

- 3.4.1 The Review was commenced by the Commission within the framework of the Electricity Act 1992 and the Rules and is now being advanced by the Authority within the framework of the Act and the Code.
- 3.4.2 The TPAG has been concerned to ensure that work undertaken and the TPM options developed by the Commission under the pre 1 November 2010 framework are consistent with the 1 November 2010 framework. In particular, the TPAG has sought to assure itself that work undertaken and the TPM options developed by the Commission are consistent with the statutory objectives of the Authority.
- 3.4.3 The TPAG has concluded that although the Commission's principal objectives and specific outcomes were broader than the Authority's statutory objective, efficiency has been the guiding principle throughout all stages of the Review.
- 3.4.4 The Authority interprets its objective to centre on efficiency considerations, given the overall requirement to act in a way that is "for the long-term benefit of consumers". The Commission also treated efficiency as its guiding principle and this can be confirmed through a review of decision documents published by the Commission covering a range of issues<sup>29</sup>.

<sup>29</sup> Available at: <http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/>.

- 3.4.5 Stages 1 and 2 of the Review (conducted by the Commission) were primarily focussed on efficiency considerations, with an evaluation of the wider regulatory framework to be addressed in stage 3. In particular:
- the options developed in stage 1 were focussed on the efficiency benefits of location-based transmission prices;
  - the analysis of options that could provide incentives to avoid/defer reliability investments developed in stage 2 was focussed on the efficiency benefits of transmission price signals;
  - the analysis of options for allocating HVDC costs was focussed on efficiency outcomes in the generation market;
  - the analysis of options for pricing SRC was focussed on incentives to minimise costs; and
  - the development of these TPM options was not influenced by fairness or environmental sustainability considerations.
- 3.4.6 The TPAG notes that changes to the statutory framework have been sufficiently significant that regardless of the current Review, the validity of the current TPM under the new framework would have needed to be considered at some point.
- 3.4.7 The TPAG has concluded that the changes to the statutory framework during the course of the Review do not require the Commission's analysis and development of alternative TPM to be reworked, and that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective. Note however that this decision does not prevent the TPAG reviewing elements of previous decisions. In particular the TPAG chose to review the GEM analysis which underpins the conclusion that there is not a demonstrable economic benefit from enhanced locational signalling.

- Q2.** Do you agree with the TPAG's assessment that the changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPMs to be reworked?
- Q3.** Do you agree with the TPAG's assessment that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective?

## 4 Analysis framework

### 4.1 Introduction

4.1.1 This section describes:

- a) the application of the CAPs to the TPAG's analysis framework;
- b) the identification of efficiency considerations to assist the TPAG in its CBA; and
- c) the counterfactual used for, and sensitivity analysis, supporting the CBA.

### 4.2 The application of the CAPs

4.2.1 To recap, the regulatory framework requires that any proposal for revised Guidelines and TPM is:

- a) consistent with the Authority's statutory objective and relevant provisions in the Act; and
- b) developed and approved in accordance with subpart 4 of part 12 of the Code.

4.2.2 The TPM is a schedule to the Code meaning any proposal to amend the existing TPM must ultimately be progressed as a Code amendment and therefore comply with the CAPs.

4.2.3 The TPAG's analysis framework is based on the statutory objective as it is applied by the CAPs. The table below describes at a high level the application of the CAPs to the TPAG's analysis.

**Table 9 The application of CAPs 1 to 3 to the TPAG's analysis framework**

	Interpretation	Application
CAP 1	Lawfulness: any change to the TPM must be lawful and consistent with the Act, come within the Authority's jurisdiction and in particular be consistent with the statutory objective. This means changes to the TPM must promote efficiency, competition and reliability for the long term benefit of consumers.	The Authority's jurisdiction under the Act includes proposed Code amendments to the TPM. The analysis under CAP 2 and CAP 3 will test consistency with the statutory objective.
CAP 2	Clearly identified efficiency gain: any change to the TPM must demonstrate a clear efficiency gain or resolve a market or regulatory failure for the long term benefit of consumers.	The TPAG has considered issues with the status quo to identify possible market or regulatory failures or potential efficiency gains for the long term benefit of consumers. <sup>30</sup>  This initial assessment does not draw on all of the efficiency considerations, rather it seeks to establish whether the threshold of a clearly identified efficiency gain or a regulatory or market failure has been met.

<sup>30</sup> Depending on the nature of the issues TPAG has focused on efficiency gains or regulatory failure. For example in considering whether changes to the HVDC charges are justified the focus has been on possible efficiency gains. Market failure has not formed part of the TPAG's analysis.

	Interpretation	Application
CAP 3	Quantitative assessment: a CBA must be applied to assess the relative efficiency benefits of the TPM options for the long term benefit of consumers. There is to be a particular focus on dynamic efficiency; competition and reliability are assessed solely in regard to their economic efficiency effects. The CBA includes sensitivity analysis.	Where appropriate, the TPAG has identified alternative options for transmission pricing.  The options have been put through a CBA using the <b>efficiency considerations</b> set out below. The options have been compared to a counterfactual based on the status quo TPM.

- 4.2.4 CAP 2 is not instructive on the question of required ‘materiality’ for an identified efficiency gain or regulatory or market failure. The TPAG has taken this to mean that where a possible efficiency gain or regulatory or market failure is identified, options should be developed to capture the efficiency gain or remedy the market or regulatory failure. The CBA (CAP 3) will provide guidance on whether there is justification to proceed with a change.
- 4.2.5 The TPAG’s judgement around the question of materiality should meet the same standard test that applies to the Authority, namely that the decision is reasonably available to the decision maker, taking into account information that is relevant to the decision.
- 4.2.6 Although the CAPs framework appears linear and the TPAG’s assessment process described in this paper follows a step-by-step process, the complexity of the issues under consideration means the decision process has been iterative as more information has become available and arguments clarified.
- 4.2.7 Where there are matters on which the TPAG has been unable to be definitive, it remains valid for the TPAG to report on those matters to the Authority and by providing the available supporting analysis provide a basis for the Authority to make its decision on that matter.
- 4.2.8 The Authority will ultimately need to address the following questions:
- Is there a proposal to amend the Guidelines and the TPM which would result in a net improvement (efficiency gain or regulatory fix) for the long term benefit of consumers (CAP 2)?
  - Have the correct options been identified?
  - Have the costs and benefits of each option been correctly identified and what is the level of confidence that they will be realised? (CAP 3)?
  - Comparing the options, which option has the highest combined net benefit associated with the highest likelihood of capturing the benefits and minimising the costs (CAP 3)?
- 4.2.9 To provide a structure to consider the costs and benefits of the options, the TPAG has identified a number of efficiency considerations which form the basis of its CBA.

### 4.3 Efficiency considerations

- 4.3.1 The Authority’s interpretation of its statutory objective supports the view that the framework for decision-making about options for the TPM should focus primarily on overall efficiency of the electricity sector for the long term benefit of consumers, while recognising that competition is an important tool to encourage efficient outcomes. Measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

4.3.2 The TPAG has found it helpful to develop a number of more specific efficiency considerations incorporating dynamic, productive and allocative efficiency<sup>31</sup> and exploring the particular implications of these for transmission pricing. These considerations have provided a structure to assess the efficiency costs and benefits of different options. Table 10 summarises the TPAG 'efficiency considerations' for transmission pricing.

**Table 10 Efficiency considerations**

Consideration	Implication
<b>1: Beneficiary pays</b>	<p>Apply a beneficiary pays approach:</p> <ul style="list-style-type: none"> <li>• where beneficiaries can be clearly identified and charges can be determined which do not exceed the beneficiaries' private benefits;</li> <li>• where the cost of identifying beneficiaries does not outweigh the benefits of doing so; and</li> <li>• to incentivise participants to provide quality information to the planning and investment approval processes, make trade offs between the costs and benefits of transmission investment and promote commercially-driven investment.</li> </ul>
<b>2: Location price signalling</b>	<p>Maintain, or provide additional, location price signals if these promote more efficient:</p> <ul style="list-style-type: none"> <li>• coordination of investment and use of transmission, generation, and Demand Side Management (DSM); or</li> <li>• trade-offs between the costs and benefits of reliability.</li> </ul>
<b>3: Unintended efficiency impacts</b>	<p>Seek efficiency gains through:</p> <ul style="list-style-type: none"> <li>• minimising any incentives arising from the TPM that could distort economic dispatch;</li> <li>• minimising any incentives arising from the TPM that create generation, DSM, or transmission investment inefficiencies;</li> <li>• adopting pricing structures that minimise allocative inefficiencies arising from the recovery of fixed and sunk costs; and</li> <li>• avoiding incentives to shift costs between participants without any corresponding efficiency gain (gaming).</li> </ul>
<b>4: Competitive neutrality</b>	Provide a level playing field for long term competition in generation and retail.

<sup>31</sup> Efficiency in the context of the CAP 2 refers to allocative, productive and dynamic efficiency. The TPAG notes that, in the context of transmission pricing:

- Dynamic efficiency relates to efficient coordination of investment in transmission, generation and demand-side initiatives, taking into account the costs and benefits of competition and reliability;
- Productive efficiency relates to the efficient operation of the electricity sector, including efficient dispatch of transmission and generation, and the level of transaction costs within the sector;
- Allocative efficiency relates to the efficient use of electricity within the economy.

Consideration	Implication
<b>5: Implementation and operating costs</b>	Take account of implementation, transition, and operating costs of market arrangements, and the administration and compliance costs of regulation. 'Implementation costs' includes consideration of whether an approach is able to be implemented within a reasonable timeframe.
<b>6: Good regulatory practice</b>	Adopt an approach that: <ul style="list-style-type: none"> <li>• is consistent between regulators;</li> <li>• is durable;</li> <li>• is consistent over time;</li> <li>• is consistent over the whole grid;</li> <li>• is compatible with market arrangements; and</li> <li>• avoids wealth transfers and step changes in prices unless these are justified by efficiency benefits. This may involve providing transition arrangements.</li> </ul>

4.3.3 These efficiency considerations are discussed further below.

#### **Efficiency consideration 1: beneficiary pays**

4.3.4 Most participants would agree, as a general principle, that the parties benefiting from particular grid assets should meet the cost of providing those assets where those beneficiaries can be clearly identified and charges can be determined which do not exceed the beneficiaries' private benefit. There are two benefits of a beneficiary pays approach, if it can be applied effectively: investment efficiency benefits through improved investment decision making and benefits in terms of improved durability of the allocation methodology.

4.3.5 Investment efficiency benefits through improved investment decision making. Parties paying transmission charges will have:

- incentives to participate in decision-making about possible new transmission investments and to provide more accurate information to Transpower and the Commerce Commission, while testing the options and costs proposed by Transpower;
- stronger incentives to make trade-offs between the benefits and the costs of transmission investment; and
- improved incentives to negotiate separate commercial agreements for some 'economic' investments in the grid rather than for them to be centrally planned and regulated.

4.3.6 The rationale is that, by engaging beneficiaries in this way, more options will be considered, alternatives to investments will receive a stronger hearing, and that trade-offs between investment costs and reliability benefits will be more actively explored. This is particularly important where the assessment of benefits requires private information to which Transpower and the Commerce Commission do not have access. The logic only holds true however if it is possible to clearly identify and charge beneficiaries up to the value they obtain. In these circumstances beneficiaries will be incentivised to accurately reveal private information, which should make the application of the regulatory test by Transpower and the Commerce Commission more robust than it might otherwise be.

- 4.3.7 If the grid investment decision does not substantially rely on private information then charging beneficiaries is less likely to improve decision making. Similarly charging parties who are not beneficiaries simply to get them to actively engage in the decision making is unlikely to improve outcomes, since Transpower and the Commerce Commission are required to fully consult and already have access to external experts and advice to identify least cost options and to challenge and justify the investments under the grid investment test.
- 4.3.8 Benefits in terms of improved durability of the methodology. Where beneficiaries can be clearly identified and are not charged more than they benefit, this can lead to improved durability of the methodology and improved regulatory certainty, through reduced disputes and interventions.

#### Issues with application of beneficiary pays

- 4.3.9 There are several issues to consider in applying a beneficiary-pays approach to allocating the cost of transmission assets:
- a) **Identification of beneficiaries.** Applying a beneficiary-pays approach requires a robust method for identifying beneficiaries that can be applied consistently across the grid. The benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively and clearly identified. In an interconnected electricity network there can be practical issues that make identifying beneficiaries costly and open to dispute. The benefits of any particular asset or set of assets can be different for different parties, and the value for different parties can vary over time. For example, the assets may provide greater reliability for one party and access to higher wholesale prices for another. Identifying users of an asset can be a proxy for identifying beneficiaries, but in an interconnected grid determining the value associated with usage can be subjective and will depend on a range of assumptions.
  - b) **Risks from over or under-allocating costs to beneficiaries.** If costs are either over or under allocated to beneficiaries there is the prospect that allocating costs to beneficiaries could contribute to poor investment decision making rather than enhanced investment decision making. For example, beneficiaries with over-allocated costs will incur costs from a new investment that exceed their private benefits and may have incentives to lobby against the new investment. Beneficiaries with under-allocated costs may have incentives to lobby for the new investment.
  - c) **Alignment between decision-rights and allocation of costs:** Where a beneficiary pays approach is used the greatest value can be obtained by having it linked to investment decision making. Ideally the beneficiaries would be identified prior to decisions being made, would have some decision-rights in the investment approval process, and the allocation of costs to beneficiaries would reflect the ex-ante value to those parties from the investment. Ideally the cost allocation to beneficiaries would also be 'fixed' at the time of each significant grid investment (i.e. not changed arbitrarily ex-post) and be structured so as to minimise any inefficiency in use of the new investment.
  - d) **Allocating sunk costs versus new investments:** There is less value to be obtained in allocating sunk costs to beneficiaries because the benefits arising from participation in the investment decision-making process are not relevant.
  - e) **Free-riding:** In a commercial environment, it is not necessary to identify all beneficiaries and free-riding is only a problem if the sum total of the free-riders' ability to hold-out prevents



welfare enhancing investments occurring. All that is required is that the full costs of an investment can be met by a subset of beneficiaries where their benefits exceed their costs. Similarly, in a centrally planned and regulated investment environment it is not necessary to identify all beneficiaries and free-riding is not a problem as free-riders cannot hold-out to delay welfare enhancing investments.

- f) **Potential distortions for efficient operation and investment:** As for any allocation to multiple customers, a beneficiary pays approach has the potential to create unintended efficiency impacts. For example, if the allocation of costs is based on usage or shares of usage then there can be an unintended disincentive to utilise the assets that have been built. This may be avoided the beneficiaries are allocated fixed shares (an incentive free allocation), but often it is not practical to recover costs in this fashion.

### Efficiency consideration 2: locational price signalling

- 4.3.10 Locational price signalling in the context of transmission pricing can incentivise:
- efficient co-ordination of generation, demand-side and transmission investment, and efficient dispatch of generation and operation of demand management; and
  - efficient trade-offs between the costs and benefits of reliability.
- 4.3.11 As a general rule the spot market provides good signals for dispatch and use of the transmission grid. However it only provides reasonable, but not perfect, signals for location of new generation, for reasons relating to economies of scale, lumpiness, lack of scarcity pricing at a nodal level, and the process of centrally planned and regulated transmission investment<sup>32</sup>. The TPM may be used to augment locational price signals from the nodal spot market in these situations and it already includes some locational price signals:
- HVDC charges;
  - connection charges; and
  - RCPD.
- 4.3.12 The RCPD interconnection cost allocation methodology is an attempt to provide additional price peak demand management signals in regions with growing net demand<sup>33</sup> requiring transmission 'reliability' investments.
- 4.3.13 The stage 2 analysis of the benefits of locational signalling for economic transmission investments concluded that the costs of additional locational signalling of economic transmission investments are likely to outweigh the benefits. However, there may be gains in providing additional locational signalling for reliability-driven investments SRC assets or from maintaining the existing locational price signalling through the TPM.

<sup>32</sup> Regulated transmission investment based on the grid investment test and meeting grid reliability standards can lead to prudent, early and lumpy transmission investments which can lead to inadequate locational signals for generation and load management.

<sup>33</sup> The RCPD charge is allocated on the basis of the average of the highest 12 (rather than 100) trading period demands in the upper south and upper north islands where demand growth is leading to increasing investments in the grid for reliability reasons. This is an attempt to 'correct' nodal prices for a lack of scarcity pricing.

**Efficiency consideration 3: unintended efficiency impacts**

4.3.14 A key function of the TPM is to provide a mechanism for Transpower to recover its fixed and sunk costs (i.e. allowed revenues) from customers. Any practical form of fixed and sunk cost recovery has the potential to involve some unintended price signals that may impact on:

- investment in new generation, DSM and transmission. These price signals may be both locational or temporal causing inefficiencies in both the location, timing and types of generation or DSM investment;
- economic dispatch;
- the use of the sunk transmission assets (allocative efficiency); and
- incentives to shift costs between participants without any corresponding efficiency gain.

4.3.15 The TPM should use an appropriate combination of fixed, peak and energy cost recovery mechanisms to minimise any unintended inefficiencies.

**Efficiency consideration 4: Competitive neutrality**

4.3.16 The TPM should, as a general rule, provide a level playing field for new investment in electricity generation, transmission and DSM (unless there is a clear efficiency gain from providing a particular price signal). For example, the TPM should not have the effect of artificially advantaging or disadvantaging particular generation technologies or company size or structures (e.g. vertical integration).

**Efficiency consideration 5: Implementation and operational costs**

4.3.17 Possible changes to the TPM will incur implementation and operational costs for industry participants, Transpower, and the Authority. The analysis of the cost of TPM options needs to form part of the CBA. The time taken to implement options is a cost that also needs to be factored into the CBA.

**Efficiency consideration 6: Good regulatory practice**

4.3.18 Good regulatory practice should seek regulation that is transparent, easily understood, defensible, certain and provides for consistent outcomes over time. Where regulators' activities overlap, these activities should be coordinated and consistent. Poor regulatory practice involving excessively arbitrary, subjective or ad-hoc regulation can in itself lead to significant inefficiencies if it creates regulatory uncertainty or incentives for wasteful lobbying.

4.3.19 Good regulatory practice for transmission pricing must comply with statutory and common law obligations to ensure:

- a) **Consistency between regulators.** Overlaps between the Authority and the Commerce Commission decision making are coordinated and treated consistently.
- b) **Durability.** Pricing outcomes are broadly acceptable to grid users (i.e. pricing outcomes that are arbitrary, subjective or ad-hoc must be avoided) and other stakeholders to ensure that the methodology is durable and does not trigger interventions either through the regulator, courts or Ministerial direction.
- c) **Consistency over time.** A principled, consistent approach is taken that over time accommodates changes in the use of and investment in the grid. This should reduce

regulatory intervention, enable market participants to more easily predict future regulatory behaviour, and thereby minimise incentives for lobbying.

- d) **Consistency over the whole grid.** A principled, consistent approach is taken for all grid assets for the same reasons as set out in (c).
- e) **Wealth transfers and step changes in prices.** The TPM is kept reasonably stable and predictable in terms of outcomes for participants. Circumstances will change over time and this may require modifications to the TPM, but changes that result in wealth transfers must be justified by clear efficiency improvements. Any proposed change must be an effective, efficient and proportionate response to the issue concerned. Where change is justified then it must be well signalled in advance and a transition should be provided so that participants can have time to adjust.
- f) **Market fit.** Any TPM is consistent with overall market design and likely market evolution.

**Q4.** The TPAG efficiency considerations: Has the TPAG identified appropriate efficiency considerations to assess the costs and benefits of different options? If not what other efficiency considerations would be appropriate?

#### 4.4 Counterfactual and sensitivity analysis

- 4.4.1 Where appropriate, assessments of alternative options have been carried out relative to a counterfactual based on a status quo TPM. The counterfactual used in the assessment in this paper includes:
  - a) the status quo TPM;
  - b) possible future electricity sector development as defined by the range of futures outlined in the latest Statement of Opportunities (SOO); and
  - c) a transmission alternatives regime, overseen by the Commerce Commission that encourages Transpower to consider alternatives to transmission investment, and is essentially similar to the existing regime.
- 4.4.2 Where appropriate, the assessment has considered the sensitivity of the results to different scenarios:
  - a) Alternative future electricity sector developments.
  - b) The introduction of an FTR between North and South Island nodes, with the holders of any FTR receiving the loss and constraint excess between the nodes.
  - c) The introduction of scarcity pricing mechanisms.

## 5 Scope of the TPAG's work

5.1.1 The scope of the TPAG's work has been governed by its terms of reference and by the scope of the stage 1 and 2 analysis and stakeholder submissions.

5.1.2 The TPAG terms of reference require the TPAG to consider the following areas:

- a) the allocation of transmission costs including those that are currently categorised as connection, interconnection and HVDC costs;
- b) providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so; and
- c) static reactive compensation.

### The TPAG's work programme

5.1.3 The TPAG's work has focused on options for HVDC cost allocation, shallower or deeper connection; and SRC. These issues are addressed in sections 6, 7 and 8 respectively. The TPAG's assessment of each issue follows the analysis framework set out in section 4 which is based on the statutory objective as it is applied by the CAPs.

5.1.4 The TPAG has taken this approach for a number of reasons.

### Allocation of transmission costs

5.1.5 Early in its work programme the TPAG decided not to pursue the stage 2 options of TPS, augmented nodal pricing and load flow based allocation. This decision logically flowed from the conclusion that there does not appear to be a demonstrable benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments. Each of these options proposed enhanced locational signalling to loads for economic transmission investments through interconnection charges. Stage 2 submissions generally supported the approach taken by the TPAG not to pursue these options further.

5.1.6 The allocation of HVDC charges has been an important focus for the TPAG and was a key issue for submitters. Analysis indicating potential efficiency gains from possible changes to HVDC charges warranted the investigation and assessment of alternative options as compared to the status quo.

5.1.7 Connection charges have been considered in the context of shallower-deeper connection.

### Incentives to avoid or defer transmission investment

5.1.8 Stage 2 analysis drew a provisional conclusion that there appeared to be a possible benefit in options that incentivise action to avoid or defer reliability-driven investments (e.g. through investment in generation and/or load management). A number of stage 2 submissions challenged this analysis.

5.1.9 The TPAG decided to consider options for shallower or deeper connection rather than "providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so". This reflects the TPAG view that there was little benefit in pursuing the bespoke pricing options identified in stage 2, as the existing RCPD interconnection charges already provide a signal for demand management in regions with growing net demand as compared to regions where growing net demand is not anticipated. The grid investment process already includes a transmission alternative regime with similarities to some variants of the bespoke

pricing option. In the TPAG's assessment introducing other general/specific bespoke transmission pricing options is unlikely to provide additional benefits, and risks conflicts with the existing RCPD mechanism.

- 5.1.10 The TPAG notes there may be opportunities for fine tuning the structure of the interconnection charge in particular the RCPD allocation approach, but has concluded that Transpower is better placed to make this assessment. The RCPD mechanism was developed by Transpower in response to the March 2006 Guidelines for TPM. Any revised TPM Guidelines should include a provision for Transpower to review the ongoing appropriateness of RCPD settings.

### **Static reactive compensation**

- 5.1.11 Work on static reactive compensation built on the stage 2 analysis and noted that stage 2 submissions universally opposed the status quo and amended status quo options. The TPAG considers that a price signalling approach to reactive power requirement in the voltage constrained USI and UNI regions has merit. Building on options proposed in stage 2 an amended kvar charge has been developed and, along with the amended status quo option, assessed against the status quo.

## **5.2 The TPAG's assessment**

- 5.2.1 The following sections of this paper contain the TPAG's assessment of the transmission pricing options for HVDC charging; for deeper or shallower connection; and for static reactive compensation.
- 5.2.2 Using the analysis framework based on the CAPs outlined in section 4 the TPAG has:
- considered the problems arising from the status quo that might indicate market or regulatory failure or the opportunity for possible efficiency gains for the long term benefit of consumers;
  - considered the possible alternative options;
  - identified the relative costs and benefits of the options, and the likelihood that of the cost and benefits using the efficiency considerations; and
  - compared the options.
- 5.2.3 While it is possible to estimate some of the efficiency costs and benefits associated with TPM options, it is recognised that the benefits of beneficiary pays and good regulatory practice are more difficult to quantify but can be significant.

## 6 Assessing options for HVDC cost allocation

### 6.1 Introduction

6.1.1 The TPAG's assessment of options for HVDC cost allocation follows the analysis framework set out in section 4 which is based on the statutory objective as it is applied by the CAPs.

6.1.2 This section:

- considers whether under the current arrangements for HVDC cost allocation, there is a possible market or regulatory failure or efficiency gain for the long term benefit of consumers sufficient to warrant analysis of alternative options;
- considers the possible alternative options;
- assesses the costs and benefits of each option by applying the efficiency considerations set out in section 4 and using the status quo as a counterfactual; and
- concludes by:
  - revisiting whether there is an efficiency gain in light of the application of the efficiency considerations to the options. At this point, the TPAG considers if there is sufficient evidence of an efficiency gain to justify a change from the status quo; and
  - comparing the costs and benefits of the options in order to identify the option which has the highest combined net benefit with the highest likelihood of capturing the benefits and minimising the costs.

6.1.3 The TPAG did not reach a unanimous conclusion so the section concludes with a majority and minority view.

6.1.4 Analysis supporting this section is contained in Appendix D.

### 6.2 Issues with the current HVDC cost allocation – Possible market or regulatory failure, potential for efficiency gains? (CAP 2)

6.2.1 The TPAG's analysis focused on whether the current HVDC charging arrangements created inefficiencies. This section references this analysis and also briefly considers the question of regulatory failure in the context of the HVDC charging arrangements. The TPAG has concluded that the level of analysis it was able to undertake was insufficient for it to rely on regulatory failure as a ground for a change from the status quo. The possibility of market failure was not considered.

6.2.2 Under the current TPM, the HVDC costs are charged to all grid-connected SI generators with an allocation proportional to peak (kW) generation based on HAMI. The HVDC charge to SI generators is expected to average approximately \$40/kW/yr in the 10-20 years following the commissioning of pole 3, although the effective charge to SI generators may be lower than this depending on how rentals relating to the HVDC assets are allocated.

#### Possible efficiency gains

6.2.3 The current HVDC charges on grid-connected SI generators create the following competition issues that may lead to inefficiencies that are described in more detail later in the text.

- 6.2.4 **Possible generation investment inefficiency from delaying SI generation.** The HVDC charge leads to a disincentive for investment in SI generation relative to NI generation as the HVDC charge adds around 10% to the total cost of a new SI project. This disincentive would lead to generation investment inefficiency if SI generation investments are delayed relative to otherwise equivalent or more expensive NI options (see paragraph 6.2.7. onwards).
- 6.2.5 **Competition effects between SI generators resulting from the HVDC charge .** The allocation mechanism for the HVDC costs would favour new generation investment in the SI by large incumbent SI generators, relative to small incumbent generators or new entrants if those new investments by the large incumbent are more likely to delay alternative NI rather than SI investments by competitors. If this arises it leads to large incumbent SI generators increasing their dominance in the SI with consequential impacts on reduced competition in generation and retail and potential inefficiency (see paragraph 6.2.17 onwards).
- 6.2.6 **Generation investment and dispatch inefficiencies from the HAMI price structure.** The HAMI allocation provides disincentives to generators to offer peak capacity and to invest in or maintain peaking generation capacity (see paragraph 6.2.28 onwards).

#### **Possible generation investment inefficiency from delaying SI generation**

- 6.2.7 The existing HVDC cost allocation provides a disincentive to invest in SI generation. If SI generation options are delayed relative to equivalent NI options as a result of the HVDC charge, this will lead to an increase in the present value cost of new generation investments and an associated economic loss.
- 6.2.8 Sections D.2, D.2.3, and D.4 in Appendix D describe an analysis of the possible increase in the present value cost of future new generation investments using the following methodology:
- A merit order of new generation base load and renewable investments is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options;
  - The new generation investments are ranked on the basis of a LRMC measure (while taking into account location factors and intermittency factors);
  - A merit order without the HVDC charge is constructed and used to derive a new investment schedule and LRMC profile to cover demand growth and plant retirement out to 2042;
  - The same approach is used to derive a merit order, new investment schedule, and LRMC profile while including the HVDC charge for SI generation options;
  - The potential economic cost is estimated by calculating the increase in present value cost between the two scenarios.
- 6.2.9 Table 11 summarises the results of the analysis. The analysis of the economic costs is dependent on a number of assumptions including the value of HVDC rentals received<sup>34</sup>, new investment costs, fuel costs and availability, exchange rates and other factors. These components cannot be known with certainty and so the analysis uses a combination of scenario and sensitivity approaches.

<sup>34</sup> SI generators may not continue to receive the HVDC rentals if the location hedging proposal goes ahead, hence sensitivity without HVDC rentals is included.

- 6.2.10 A standard scenario approach is used to account for the impact of alternative ‘states of the world’. However the impact of an HVDC charge also depends on the relative costs of projects. These will vary significantly from site to site depending on the quality of the resource, the cost of connection to the grid, the resource consent limits and the international costs equipment at the time that these projects are committed. These cost variations will only become apparent during the process of project investigation, planning and resource consenting. The analysis accounts for this potential project cost variation by randomly sampling project capital costs.
- 6.2.11 The detail of the scenario and sensitivity analysis is reported in section D.4 of Appendix D. The analysis uses a list of potential projects that was developed by the Commission for the SOO published in September 2010 and used by the Ministry of Economic Development in its Energy Outlook published in December 2010. This list has been developed over a number of years and has been consulted on and used in modelling work for transmission investments and other electricity sector issues.
- 6.2.12 The list of projects includes around 960MW of NI geothermal, 2900MW of NI wind and 1360MW of SI wind, 470MW of NI hydro and up to 2240MW of SI hydro, 310MW of NI cogeneration and 42MW of SI cogeneration. Much of the hydro is relatively high cost. It also includes a number of NI gas fired thermal options which may be viable if there is sufficient local gas available at a reasonable cost. Additional coal fired options are also possible based on SI, NI or imported resources and may be viable if coal and carbon prices are low enough, but this is not considered likely. There are numerous peaking options, but these are not used in this analysis as it focuses on new projects to meet the demand for ‘energy’ rather than peaks. The general level of costs of these projects has been updated to reflect more recent information. However, as discussed above, these costs will always be subject to considerable uncertainty which is accounted for through the scenario and sensitivity analysis.
- 6.2.13 The result of the analysis is a range of present value cost of \$14m to \$64m attributable to the HVDC charge. The lower end of the range applies in scenarios and sensitivities where there is a large quantity of NI generation options that have a lower cost than SI options and hence the HVDC cost allocation does not have a significant impact for a number of years. Note that in all cases it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. The lower levels of economic cost arise from there being a significant block of cheaper NI wind. Note that approximately twice as much potential wind is assumed to be available in the NI as in the SI and hence there is the potential for a delay in the impact of the HVDC charge if much of this NI resource is cheaper than the SI.
- 6.2.14 The upper range of economic cost applies in scenarios where there are some SI options which are of a similar or lower cost to NI options and hence the HVDC cost allocation results in a much more significant delay in the development of these lower cost SI options from an earlier date, and SI generators no longer receive HVDC rentals. This can also occur in the scenario where it is assumed that there is sufficient local gas supply available for additional CCGT projects in the NI in the 2020s that have a similar cost to NI and SI options. In this case an HVDC charge could delay cheaper SI options by many years and hence result in a higher present value cost.



- 6.2.15 Table 11 suggests that the generation investment inefficiency associated with the current HVDC charge could be between \$14m and \$51m (average \$31m, standard deviation \$10m<sup>35</sup>) if SI generators continue to receive HVDC rentals, or between \$19m and \$64m (average \$38m, standard deviation \$13m) if they don't. Although these costs are small relative to the present value of future generation investments (approximately \$7-8 billion over 30 years), they are consistently positive. If the analysis suggesting these costs is robust, if the costs are considered material, and if the costs of changing the pricing are low, then there should be justification to make changes to avoid these costs.
- 6.2.16 The analysis does not take into account a range of factors that are not possible to model but that may have an impact on the size and likelihood of the inefficiency for example: generation investors' strategies, physical hedging positions, capital constraints and the likelihood of projects gaining resource consents.

**Table 11 Generation Investment Inefficiency of HVDC charge (HAMI allocation)**

HVDC rentals	Net HVDC cost	Economic cost (NPV \$m)
SI generators continue to get HVDC rentals	\$35/kW/yr	\$14-51m (average \$31m)
SI generators don't get HVDC rentals	\$40/kW/yr	\$19-64m (average \$38m)

#### Competition effects between SI generators resulting from the HVDC charge

- 6.2.17 The Commission suggested<sup>36</sup> that, under certain circumstances, the current allocation of HVDC costs favoured new generation investment in the SI by large incumbent SI generators, relative to small incumbent SI generators or new entrants. This is because total HVDC charges are fixed and any new investment in SI generation will simply result in a reallocation of these charges between the existing payers and new generators. All incumbents will benefit from a reduction in their share of the costs, and the largest incumbents will benefit the most.
- 6.2.18 A new entrant, with no existing share of the HVDC costs, will not share in this reallocation benefit and will face the full HVDC cost for its new generation. A large incumbent such as Meridian (currently meeting around 70% of HVDC costs) will get a significant benefit from the reallocation. This means that the effective HVDC charge it faces can be substantially less than a new entrant or a much smaller incumbent (the effective charge is equal to the full charge for the new investment minus the reduction in the existing charges).
- 6.2.19 However, some submitters to the Stage 2 Consultation Paper suggested<sup>37</sup> that the Commission's analysis was incorrect and that all generators face the same marginal cost of increased capacity

<sup>35</sup> Note that the standard deviation in the impact of a certain HVDC charge is significantly less than the standard deviation in the total LRM of new investment costs as the latter includes the large uncertainty in the underlying capital, operation and fuel costs for all new investments whereas the former only includes the uncertainty in the relative timing of new investments arising from the HVDC charge.

<sup>36</sup> Transmission Pricing Review: Stage 2 options consultation paper, p29.

<sup>37</sup> See submission from RTANZ, available at: <http://www.ea.govt.nz/document/11154/download/our-work/consultations/transmission/tpr-stage2options/submissions/>

regardless of SI market share. This is because, provided that a similar investment would be made by a competitor in the SI, the incumbent would obtain the benefit of reduced HVDC charges on its existing generation regardless of whether it or a competitor built the new capacity in the SI.

- 6.2.20 The TPAG concludes that both claims can be true, depending on assumptions about other investments that could be displaced by the new SI generation. If the new generation is assumed to displace another SI generation option on a one-for-one basis, then it is correct that all SI generators will face the same incremental cost. On the other hand, if the new generation does not have the effect of displacing other new SI generation, the Commission's analysis is correct, and large incumbent generators will have an advantage in new generation investment.
- 6.2.21 In practice one cannot be certain about what would occur in the absence of a new investment by one of the incumbent SI generators, and different incumbents are likely to make different judgements about what is likely and what their cost relative to a competitor's cost will be. To accommodate these uncertainties the TPAG has developed three investment counterfactuals.
- 6.2.22 If the counterfactual is that an identical investment would otherwise be made by a competitor in the SI, then the incremental cost for all investors would be the full HVDC charge since the incumbent would have obtained the benefit of reduced HVDC charges on its existing generation whether it or a competitor built the new capacity in the SI. However if the counterfactual is that a NI investment would otherwise be made then the incremental cost would be much lower for a large incumbent (such as Meridian) than its SI competitors.
- 6.2.23 It can be shown algebraically that the incremental HVDC cost for an incumbent SI generation company is somewhere between 100% of the full HVDC charge and 100% less its existing HVDC cost share, depending on the investment counterfactual it faces when it invests<sup>38</sup>. A counterfactual that lies between the two extremes has therefore been developed for the purpose of this analysis.
- 6.2.24 The potential counterfactuals and the impact on the largest incumbent (Meridian with approximately 70% share of HVDC charges) are described in section D.6 of Appendix D and are summarised in Table 12. This shows that Meridian can have a significant artificial competitive advantage over smaller competitors and new entrants in 2 of the 3 possible counterfactuals.

<sup>38</sup> This issue was raised in submissions by RTANZ, Norske Skog, Meridian and TrustPower. RTANZ claim that counterfactual 1 applies and everyone investing in the SI faces the same opportunity cost. Norske Skog agrees this is an issue, but believes it can be resolved by only charging HVDC costs to existing generation. Meridian and TrustPower focus on counterfactuals 2 and 3 and sees the current allocation as a barrier to new investors in grid connected SI generation. An algebraic derivation is provided in the Appendix to Norse Skog's submissions to the Stage 2 consultation paper., <http://www.ea.govt.nz/document/11150/download/our-work/consultations/transmission/tpr-stage2options/submissions/>

Table 12 SI generation investment counterfactuals

Option	Description	Meridian's net incremental cost from HVDC charge
<b>Counterfactual 1</b>	Meridian assumes that if it invests in the SI it will displace a competitor investment in the SI	\$35/kW/yr
<b>Counterfactual 3</b>	Meridian assumes that if it invests in the SI it will displace a NI investment and will have no impact on a competitor investment in the SI	\$11/kW/yr (100%-70%)*35
<b>Counterfactual 2</b>	In practice, the large incumbent generator will be uncertain about the outcomes and the effective HVDC cost will likely lie between Counterfactual 1 and Counterfactual 3. For counterfactual 2 it has been assumed that the cost impact is half way between the two extremes.	\$23/kW/yr

- 6.2.25 It is not possible to know which counterfactual will apply over the next 30 years. It seems likely that it will be closer to counterfactual 3 than 1 in the next few years given that SI generation options compete directly with relatively low cost NI options in a national market. However under counterfactual 3 Meridian has a substantial \$24/kW (\$35 less \$11) advantage over its SI competitors. If this was the case, Meridian is likely to increase its dominance in the SI.
- 6.2.26 Providing an artificial competitive advantage to Meridian is undesirable, but it is difficult to estimate the economic cost of Meridian increasing its dominance in the SI. For this reason the generation inefficiency estimates in the analysis are based on the results for counterfactual 1, which does not give Meridian an artificial competitive advantage<sup>39</sup>.
- 6.2.27 In submissions Todd suggested that the HVDC charges could create an uneven playing field in favour of lines companies looking to invest in generation within their network, and Meridian, Todd and Opuha Water suggested that the current charge provides an incentive to embed generation, at the possible cost of lost economies of scale and increased distribution losses. This is considered to be a second order issue and has not been quantified.

### Generation investment and dispatch inefficiencies from the HAMI price structure

- 6.2.28 The HAMI price structure raises a number of specific issues. This methodology may provide incentives to:
- withhold offers of short-term grid-connected generating capacity in the SI;
  - mothball or retire existing grid-connected peaking capacity in the SI;

<sup>39</sup> It is shown in section D.6 of Appendix D that the investment inefficiency is lowest under counterfactual 3 and is greatest under counterfactual 1. The analysis of generation inefficiency uses counterfactual 1 on the grounds that any reduction in generation investment inefficiency under counterfactuals 2 and 3 is offset by the costs of Meridian increasing its dominance in the SI. These estimates provide a lower estimate of the total economic inefficiency if the cost of Meridian increasing its dominance is greater than \$5-10m NPV. We note that the Government considers Meridian's dominance in the SI market as a significant enough issue to justify virtual and physical asset swaps.

- c) discourage investment upgrading existing grid-connected generation to provide additional peaking capacity in the SI; and
- d) bias new SI grid-connected generation towards energy rather than peak capacity (for example in the design of new wind and hydro schemes).

- 6.2.29 Under the HAMI cost allocation, grid-connected SI generators face a high initial cost when they offer peak generation above their highest previous injection, since they will incur HVDC charges for the following 5 years if it is dispatched. Although they will get the benefit of dispatching peak generation up to this level for the following 5 years at no further additional cost, they will be uncertain if these benefits will outweigh the costs. This feature of the HVDC charging structure tends to make generators reluctant to offer peaking capacity even when the value is relatively high. Some generators report they are withholding over 100MW of peaking capacity in the SI as a result<sup>40</sup>. This capacity is available for grid emergencies as Transpower has agreed not to adjust generators' HAMI in these situations, but it is not being made available at other times.
- 6.2.30 This withholding of capacity can lead to dispatch inefficiencies which the Commission estimated to be towards the lower end of a \$0-100m range<sup>41</sup>. The TPAG considers that this dispatch inefficiency is more likely to be in the range \$0-\$10m NPV. One reason that SI generators may be withholding capacity from the market to avoid the HAMI charges may be owing to constraints on the HVDC limiting the transfer, and therefore value, of SI peaking capacity. It is likely that much of this withheld capacity would be returned to the market once the marginal value of SI peaking increases after pole 3 is commissioned. The influence of HVDC firm capacity on the value of SI peaking generation is considered in more detail in Appendix D, section D.9.
- 6.2.31 In addition to the dispatch inefficiency there is potential generation investment inefficiency from discouraging new peaking capacity in the SI which is estimated to have an economic cost in the range \$0-37m NPV<sup>42</sup>. This is considered in Appendix D, section D.9. This investment inefficiency depends on there being up to 200MW of additional peak capacity available from either upgrading existing hydro capacity or from modifying the design of new generation to provide additional peaking capability, which is up to \$35/kW/yr cheaper than NI peak capacity options.

**Table 13 Potential peaking generation inefficiency from the HAMI allocation methodology**

HVDC Rentals	Net HVDC cost	Withholding existing peaking capacity	Peaking investment inefficiency (200MW)
		Economic Cost (NPV \$m)	
<b>SI generators continue to get HVDC rentals</b>	\$35/kW/yr	\$0 to \$10m	\$0 to \$37m
<b>SI generators do not get HVDC rentals</b>	\$40/kW/yr	\$0 to \$11m	\$0 to \$42m

<sup>40</sup> See page 28 of the Stage 2 Consultation Paper

<sup>41</sup> See page 28 of the Stage 2 Consultation paper. The upper bound was based on the worst case scenario in which the withholding of SI capacity led to the construction of 100MW of unnecessary NI peaking capacity. The lower bound of zero was based on the assessment that there is sufficient incentive for SI generators to offer their available capacity at peak times. However despite this a number of SI generators are not currently offering their full capacity and hence there is likely to be some cost, but much closer to zero than \$100m.

<sup>42</sup> See section D.9.

6.2.32 Although there is a significant risk of economic investment inefficiency from the HAMI cost allocation methodology, the actual economic inefficiency arising is quite uncertain and depends on SI generator behaviour following the commissioning of pole 3 and the quantity of peak upgrade options which are cheaper than the NI peaking options that they might displace.

### Conclusion

6.2.33 This section has discussed and concluded that:

- there is a disincentive for new grid-connected generation in the SI relative to NI which will lead to generation investment inefficiencies of between \$14m and \$64m NPV if the assumptions made in the analysis are robust;
- there is a risk that there is a lack of competitive neutrality between large SI incumbents and new SI entrants;
- the HAMI allocation discourages investment in new grid-connected peaking capacity in the SI resulting in the risk of an investment inefficiency of up to \$42m NPV; and
- the HAMI allocation encourages the withholding of grid-connected SI peaking capacity from the market resulting in the risk of a dispatch inefficiency of up to \$10m NPV.

6.2.34 To be consistent with the statutory objective the TPM must promote efficiency, competition and reliability for the long term benefit of consumers. Changes to the status quo should be contemplated if there are potential efficiency gains available. There was not unanimous agreement amongst the TPAG members on the materiality of the efficiency gains, but the TPAG concludes that there is sufficient evidence of potential efficiency gains to warrant analysis of alternative TPM options.

**Q5.** Do you agree there was sufficient evidence of a clearly identified opportunity for an efficiency gain to warrant analysis of alternative options for the allocation of HVDC costs? In particular do you agree with the assumptions and analysis contained in section 6.2 and further elaborated in Appendix D? If you do not agree please set out your reasons for reaching an alternative conclusion.

### Regulatory failure?

6.2.35 The TPAG has not undertaken sufficient in depth analysis on whether the HVDC charges are a regulatory failure to draw a conclusion on regulatory failure to justify (or not) a change from the status quo arrangements but makes the following observations.

6.2.36 There is an argument that the current HVDC charges constitute a form of regulatory failure, in that the status quo arrangements which allocate HVDC charges to SI generators while in part based on a beneficiary pays approach, is inconsistent with the application of the beneficiary pays approach as proposed in this paper (See discussion in the section following paragraph 6.4.2). In addition the charging arrangements for the HVDC are inconsistent with the allocation of the costs of other similar assets. These factors can lead to on-going disputes and regulatory uncertainty.

6.2.37 Paragraph 6.4.7 onwards set out the issues that make it hard to clearly and objectively identify beneficiaries of the HVDC; explain that the beneficiaries are likely to change over time; and that identifying the beneficiaries of other interconnection assets could be less problematic.

- 6.2.38 The allocation of HVDC charges to grid-connected SI generators under the existing transmission pricing Guidelines was implemented partly under a beneficiary pays approach by the Commission. The application of a beneficiary pays approach was one of the many considerations in arriving at a decision on who should pay for the existing and any new investment in the HVDC link. A change in circumstance or view as to how a beneficiary pays approach should be applied does not, however, constitute a regulatory failure, any more than a change in commercial circumstance would invalidate a commercial contract (unless that was part of the contract). Regulatory stability is also an important principle that promotes dynamic efficiency. Given there has been no stable consensus view on how a beneficiary pays approach should be applied so as to identify beneficiaries, and the amount by which they benefit from the HVDC link, the case for a regulatory failure in the application of a beneficiary pays approach has not been made.
- 6.2.39 Whilst the HVDC costs are allocated in a different way to other interconnection assets, this is not a reason to change unless there is an efficiency gain.
- 6.2.40 The TPAG does not dismiss the possibility for there to be a finding of regulatory failure but it has not been the focus of the TPAG's work.

### 6.3 The options

- 6.3.1 The Stage 2 Consultation Paper suggested that there may be material benefits in alternative HVDC charging regimes. The TPAG has similarly concluded that there is sufficient evidence of potential efficiency gains to warrant analysis of alternative TPM options. The Stage 2 Consultation Paper proposed three possible alternatives to the status quo: a MWh allocation to SI generators; a postage-stamped allocation to all load, generation or a mix of load and generation; and an 'incentive-free' allocation to existing SI generators; and considered a further capacity rights option (proposed by NZIER).
- 6.3.2 The TPAG has assessed the stage 2 options along with a further transitional option developed by the TPAG. The options are described in Table 14.
- 6.3.3 For each of these options there are a number of variants, some of which were suggested by submitters on the Stage 2 Consultation Paper. The TPAG has not assessed all of the variants against its efficiency criteria.

**Table 14 HVDC stage 2 Options assessed by the TPAG relative to the status quo**

Option	Description	Rationale for Change
<b>Status quo</b>	HVDC costs are met through a charge on grid-connected SI generation plant with charges based on HAMI.	
<b>HVDC capacity rights</b>	The basic principle of the capacity rights approach is that generators would need to purchase capacity rights in order to use the HVDC link.	The objective would be to use a market mechanism to discover the beneficiaries of the HVDC link and to allow the market to price rights to use the HVDC link.

Option	Description	Rationale for Change
<b>MWh allocation</b>	HVDC charge would remain on grid-connected SI generators but would be allocated proportionately to generation in MWh rather than based on HAMI.  The per-MWh allocation could be based on shares of generation over the previous year, or over several years to avoid year to year variation due to hydrology.	The effect of changing to a per-MWh charge would be to avoid penalising peak injections which discourages investment in peak generation or generators operating to their peak capacity.
<b>'Incentive-free' allocation to SI generators</b>	HVDC charge would remain on existing grid-connected SI generation plant, but would be allocated in a way that does not influence either the investment or operational behaviours of SI generators.	The objective would be to find an 'incentive-free' means of allocation that did not distort dispatch or investment decisions.
<b>Postage stamp</b>	HVDC costs would be spread broadly throughout New Zealand over offtake, in the same manner as interconnection assets are charged currently.	The objective would be to avoid possible distortion to competition in generation investment and dispatch.
<b>Postage stamp transition</b>	As for postage stamp, but incorporating a transitional 'incentive free' allocation to existing grid-connected SI generating stations.	As for postage stamp, while removing large step changes in prices and wealth transfers.

6.3.4 The possible variants to the assessment options are described below in more detail. Where the choice of variant would impact the analysis, this is discussed.

#### **Variants of the HVDC capacity rights options**

6.3.5 Some submitters to the Stage 1 and 2 Consultation Papers suggested that HVDC capacity rights might be a useful market-based approach to identify beneficiaries of the HVDC link and allocate costs. There are two potential forms of HVDC capacity rights that might be considered; a merchant link model whereby parties funding a new investment in the HVDC receive dispatch rights and rentals on the capacity they pay for; and the NZIER proposal<sup>43</sup> which involves an allocation or auctioning of physical rights to transfer energy across the link. The two forms of capacity rights are summarised in Table 15.

<sup>43</sup> See "A capacity Rights Regime for the HVDC Link", NZIER Report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010.

Table 15 Capacity rights options

	NZIER Proposal	Merchant Link Proposal
<b>Overseas model</b>	None that the TPAG is aware of.	Australian market interconnector regime <sup>44</sup> .
<b>Concept</b>	Generators wishing to 'use' the HVDC would need to hold an HVDC Capacity Right to be dispatched.	Users paying for link capacity rights would receive rentals and would be able to 'offer' link capacity into the market in competition with generators in the sending and receiving regions.
<b>Initial allocation</b>	Rights to use the existing HVDC could be auctioned or allocated according to some measure of historical 'use' or 'benefit'. Rights to new capacity could be given to parties that pay.	Dispatch rights to the existing HVDC could also be auctioned or allocated, and rights to new capacity could be given to parties who pay.  There could be separate dispatch rights for capacity in each direction.
<b>Secondary trading</b>	Requires half hour secondary trading up to gate closure and a separate spot auction of rights.	Additional secondary trading may occur if there is a demand, but is not required.
<b>Market clearing and Settlement</b>	Requires a 2 solve process <sup>45</sup> to identify 'users' <sup>46</sup> of the HVDC, and integration of separate spot trading regime. Energy and reserve prices will be affected.	SPD needs to be modified to include link offers, but otherwise it is co-optimised and settled as now. Energy and reserve prices will be affected.

### Variants of the MWh option

- 6.3.6 Todd and Meridian suggested an alternative MWh allocation whereby the HVDC costs could be allocated to generators and loads in each island based on MWh flows in each direction. northward flows could be shared equally between SI generators and NI loads and southward flows could be recovered from all loads. Other sharing formula would also be possible. For example, a more symmetrical approach would have southward flows being shared between SI customers and NI generation. It is noted that flows may not necessarily reflect value, and that some account of the price differences could also be used in a sharing formula to reflect this.
- 6.3.7 The issues associated with these variants are discussed in the Table 16.

<sup>44</sup> The only remaining market interconnector in the Australian market is Basslink. MurrayLink and Directlink were built as merchant links, but have now been converted to regulated status.

<sup>45</sup> There are detailed implementation issues and modifications to deal with spurious results and to handle losses and constraints as described in "NZIER Capacity Rights Proposal – Implementation Issues", Electricity Authority 30 November 2010. <http://www.ea.govt.nz/document/12161/download/our-work/advisory-working-groups/tptg/7Dec10/>

<sup>46</sup> Although it may be possible to identify "users" of the HVDC using this 2 solve approach, it would be much more difficult to identify all the possible "beneficiaries" and it would be very costly to require that all these parties actively trade link rights to match



Table 16 MWh Allocation Variants

	<b>Option for assessment: allocate to SI generators on MWh shares over several years</b>	<b>Variant: allocate to SI generators/NI load for S-&gt;N flows and to SI customers/NI generators for N-&gt;S flows.</b>
<b>Competition issues and generation investment inefficiency</b>	Avoids SI peaking inefficiency, and reduces generation investment inefficiency, but may introduce dispatch inefficiencies which could become significant if there was SI thermal generation <sup>47</sup> .	Would avoid SI peaking inefficiency and further reduce generation investment inefficiency, but may introduce other dispatch inefficiencies.
<b>Impact on end-user costs</b>	None.	Difficult to predict the net impact of flow varying customer transmission costs and flow on impacts of the cost allocation to generators on wholesale prices in each island.
<b>Long run impact on end-user costs</b>	May be small positive impact from slightly lower LRMC in SI.	Difficult to predict net effect of customer transmission charges and flow on impact on LRMC and Short Run Marginal Cost (SRMC) on wholesale prices.
<b>Consistency across grid.</b>	Same as status quo.	Similar to Status quo but a more complex sharing arrangement.
<b>Consistency over time.</b>	Only a minor change to status quo.	Significant change to status quo, and likely to be unstable over time because of variations in hydro inflows.

6.3.8 The alternative MWh allocation methodology described in Table 16 which involves a more complex allocation between NI/SI load and generation on the basis of relative shares of South->North and North->South flows has not been treated as a full separate option. This is because the allocation to SI generators would achieve the main efficiency gain with respect to peaking generation inefficiency with a lower risk of other dispatch distortions and with no price impacts on end users.

#### **Variants of the postage stamp options**

6.3.9 The potential generation investment inefficiency can be avoided if new SI generation is not required to pay HVDC charges through postage stamping of HVDC charges. There are several options to implement postage stamping. For example HVDC charges could be included with other interconnection assets and recovered from customers through existing RCPD charges or they could be recovered via a MWh charge on all generators, or via a mix of MWh charges on all generators and all customers. The economic impacts and the impacts on end-user costs of these alternatives are expected to be similar (see Table 17), so they have not been treated as separate options for the purpose of this analysis.

<sup>47</sup> If there was a SI thermal plant a MWh charge to SI generators may lead to more expensive NI thermal plan being dispatched ahead of it. This would be inefficient.

Table 17 Postage stamp allocation variants

	<b>Option for assessment: allocate to offtake via interconnection charge</b>	<b>Variant: allocate to all generation on MWh</b>	<b>Variant: allocate 50% to all offtake and 50% to all generation on MWh</b>
<b>Competition issues and generation investment inefficiency</b>	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.
<b>Initial impact on end-user costs</b>	\$3/MWh increase in average transmission costs <sup>48</sup> .	\$3/MWh immediate increase in wholesale prices as additional variable cost to all generators flows through.	\$1.5/MWh increase in transmission charges and \$1.5/MWh increase in wholesale prices.
<b>Long run impact on end-user costs</b>	\$3/MWh transmission cost increase offset by flow on impact of around \$10/MWh reduction in SI LRMC relative to NI.	\$3/MWh increase in wholesale offset by flow on impact of around \$10/MWh reduction in SI LRMC relative to NI.	\$3/MWh increase in wholesale and transmission costs offset by flow on impact of around \$10/MWh reduction in SI LRMC relative to NI.
<b>Consistency across grid.</b>	Consistent treatment of interconnection assets.	Differing treatment of interconnection assets.	Differing treatment of interconnection assets.
<b>Consistency over time.</b>	Significant change on implementation but consistent over time.	Significant change on implementation but consistent over time.	Significant change on implementation but consistent over time.

6.3.10 These alternative implementations could be explored further if postage stamping is a preferred option.

#### **Transition to postage stamping the HVDC charge**

6.3.11 The objectives of a transition to postage stamping would be to avoid the short term step changes in prices to consumers that would occur under a change to postage stamping the HVDC costs, while at the same time maintaining any efficiency benefits resulting from a postage stamp approach and providing a net-benefit to consumers.

6.3.12 Under a transition to postage stamping, existing grid-connected SI generation would be required to pay for a portion of the HVDC charges which could be phased out over a transitional period. Ideally the allocation between existing grid-connected SI generators over the transitional period

<sup>48</sup> This is estimated on the basis of \$147m real HVDC revenue requirement in 2013/14 minus \$14m expected HVDC rentals over total NZ off take demand of approximately 42,000GWh.

would be fixed in advance so as to remove any incentives that could distort behaviour and create inefficiencies. This could be done, for example, on the basis of historical share of HVDC charges, allocated to specific generating stations.

- 6.3.13 The allocation of costs to existing grid-connected SI generation stations and the length of the transition can be chosen to avoid step changes in prices, allocative inefficiencies and value transfers. The length of the transition can also be set so as to make an incentive free allocation workable. In addition the transitional arrangements can also accommodate the value impact to the SI generators of no longer receiving the HVDC rentals so as to avoid competition issues arising from existing SI generators being recipients of the net proceeds of FTR auctions in which they participate.
- 6.3.14 There is a range of different transition options, each with a different level of allocation of HVDC costs and a different transition duration and phasing.

**Table 18 Postage stamp transition variants**

Initial charge to existing SI generation	\$45/kW	\$30/kW/yr	\$23/kW/yr
Term	5	10	15
Competition issues and generation investment inefficiency	Avoids new generation competition issues and peaking and dispatch inefficiency from delaying investment in cheaper SI options as transitional allocation to existing SI generation is 'incentive free'. Also enables rights to HVDC rentals to be transferred to customers as part of transition.		
Initial impact on end-user costs	No increase in transmission costs.	\$1/MWh increase in transmission charges.	\$2/MWh increase in transmission charges.
Durability of incentive free allocation	high	medium	low
Medium / Long run impact on end-user costs	Risks that there may be \$1-2/MWh increase in end-user costs if it takes longer than 5 years for the impact of lower SI LRMC to flow through.	Low risk that there is a net increase in end-user costs above \$1/MWh and likelihood of a net decrease after 10 years.	Low risk that there is a net increase in end-user costs above \$1/MWh beyond 10 years.
Consistency across grid.	Consistent treatment of interconnection assets, but different treatment of new and old SI generation during transition.		
Consistency over time.	Provides a short transition.	Provides a medium, term transition	Provides a longer term transition.

- 6.3.15 The postage stamp transition options are discussed in more detail in section 6.6.2.

**Q6.** Do you agree with the range of HVDC options identified for assessment? If not, why not?

## 6.4 Assessment of options against efficiency considerations

6.4.1 This section applies the efficiency considerations set out in section 4 to each option relative to the status quo.

### Efficiency consideration 1: Beneficiary pays

6.4.2 Recapping section 4, where beneficiaries and shares of costs can be readily identified, there are two possible benefits from applying a beneficiary-pays approach to the allocation of transmission costs:

- a) investment efficiency benefits through improved investment decision making; and
- b) benefits in terms of improved durability of the methodology and improved regulatory certainty.

6.4.3 However, as set out in section 4, there are several issues to consider in applying a beneficiary pays approach to allocating the costs of transmission assets.

6.4.4 This section:

- a) considers issues in applying the beneficiary pays approach to the allocation of HVDC costs;
- b) considers the possible benefits from applying a beneficiary pays approach to the allocation of HVDC costs; and
- c) assesses the extent to which the options apply a beneficiary-pays approach compared with the status quo.

### Issues in applying a beneficiary pays approach to the HVDC costs

6.4.5 Section 4 identified issues that would need to be considered in applying a beneficiary pays approach. These are summarised briefly in Table 19.

**Table 19 Issues with application of beneficiary pays approach**

Issue	Brief description
Identifying beneficiaries	It is important to apply the beneficiary-pays approach consistently across the grid and that beneficiaries can be clearly and objectively identified.
Risks from over or under allocating costs	Over or under allocating costs to beneficiaries risks contributes to poor decision-making.
Decision rights	Ideally allocation of costs to beneficiaries should be linked to decision rights.
Sunk costs	Allocating sunk costs to beneficiaries will not improve decision-making if no future investments planned in near term.
Free-riding	This is not relevant while HVDC grid investments are centrally planned and subject to a regulatory test; the costs can be met by a subset of beneficiaries.
Potential distortions	It is important to avoid unintended negative efficiency impacts from the cost allocation.

The following sections assess the first four of these issues in the context of applying beneficiary-pays to the HVDC link. As noted in Table 19, HVDC investment is subject to a regulatory test so the issue of free-riding is not relevant and the issue of potential distortions is relevant to the structure of charges whether or not the beneficiary pays approach is applied.

### ***Identifying beneficiaries***

- 6.4.6 Under current arrangements the HVDC costs are allocated to grid-connected SI generators, while the Alternating Current (AC) interconnection costs are allocated to offtake. The application of a beneficiary pays approach was one of the many considerations, driven by the application of the pricing principles, in the Commission's decision on who should pay for the existing and any new investment in the HVDC link. The Commission, in the explanatory paper for its final decision on HVDC pricing methodology (March 2006) considered that beneficiaries of the HVDC link were widespread but not all beneficiaries would face strong incentives (or be able ) to identify least cost investment options if they were paying for new and replacement investments in the HVDC link. This consideration stemmed from its interpretation of Rule 2.2 of section IV of Part F<sup>49</sup>. Rule 2.2, along with the other pricing principles has been removed from the Code.
- 6.4.7 The TPAG has considered what might be involved in identifying the beneficiaries of the HVDC link. It considered this from two perspectives: using a regulated approach; and using HVDC capacity rights as a market-based approach to identifying beneficiaries.

### *Using a regulated approach to determining beneficiaries*

- 6.4.8 A beneficiary assessment was not applied when pole 3 was approved<sup>50</sup> as part of the grid investment test, however the TPAG has discussed what would have been involved in such an assessment and the likely implications. In the TPAG's view, a beneficiary assessment would have required estimates of market price duration curves and an examination of the likely impact on existing market participant portfolios for the case for pole 3 replacing pole 1, relative to the case where pole 1 was retired.
- 6.4.9 The HVDC link provides a mix of benefits that varies according to time frame and circumstance. For example it primarily benefits<sup>51</sup>:
- a) SI generators and/or NI customers in very wet periods;
  - b) SI customers and/or NI generators in dry periods;
  - c) NI customers and/or SI generators in peak demand, low wind or thermal plant outage periods; and
  - d) NI generators and/or SI customers in very windy periods when demand is low and thermal units are backed down to minimum.

<sup>49</sup> "2.2 the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;"

<sup>50</sup> It is recognised that the commercial and regulatory environment has changed significantly since pole 1 and pole 2 were committed and hence there is little point in speculating on how the beneficiary pays approach would have been applied to these decisions.

<sup>51</sup> It is noted that the benefits to particular categories of customers and generators can be modified by commercial and contractual arrangements, and there are also other possible system benefits.

- 6.4.10 The benefits arising in these different circumstances depend not only on the direction and magnitude of the power flows, but also on the prices in each island. For example, there may be many periods of relatively low flow across the HVDC link when price differences and hence benefits are low, while a significant percentage of the total benefit may arise in a much smaller number of periods when price levels and price differences are very high (e.g. very dry years or periods of capacity constraint).
- 6.4.11 The relative size of these benefits depends on a range of external factors that influence the merit order of new generation options (e.g. capital cost, exchange rates, resource availability, resource consents, international oil, gas and coal prices, local fuel supply and cost, new technology, and carbon prices). For example:
- a) If there is a significant amount of geothermal capacity available at a lower cost than SI renewable options, or if there is a major NI gas discovery and low carbon prices, and SI demand continues to grow, then the balance of benefits will progressively move from SI generators/NI customers to SI customers (who will benefit from access to cheaper NI generation and dry year backup).
  - b) In a world where thermal options are not competitive with renewable as a result of high carbon prices and restricted local coal and gas supply, the HVDC link can allow a balanced development of renewables taking advantage of diversity in both investment costs and operational requirements (for example, wind flows and hydro inflows). The benefits of this are likely to be shared between the different groups.
  - c) If carbon prices are very high and local gas supply becomes very restricted then existing NI thermal generators may be retired. These could be replaced by renewable options and, depending on the relative availability and cost of renewable options in each island, the HVDC link can provide benefits, by providing access to the cheapest alternative in either island, sometimes in the South and sometimes in the North (it is difficult to know which, as most renewable options are limited by resources and the costs are relatively site, rather than island, specific). In this case the diversity value of having access to peaking capacity in either island is likely to increase as the percentage of wind on the system increases.
  - d) If there is a significant and sudden loss of demand in the SI then the HVDC link will provide benefits to SI generators/NI customers until a new equilibrium is established.
- 6.4.12 Apportioning benefits between groups would require judgements on the nature and probability of these different states of the world. These judgements are likely to be subjective and debateable.
- 6.4.13 Further, the replacement of pole 1 by pole 3 provides a number of additional system benefits relating to reserves, security, losses, and competition, for which it is difficult to identify particular beneficiaries. For example:
- a) The replacement of pole 1 with pole 3 retains the existing bi-pole operation and this has significant advantages over a monopole operation. The reserve requirements with a monopole are significantly greater (one pole can help cover the risk of failure of the other and losses are significantly lower). Also a bi-pole configuration increases the flexibility of system operations to deal with other high impact, low probability, events that could occur elsewhere in the electricity supply system. This will improve the overall reliability of supply.

- b) Technical control equipment provided with pole 3 may facilitate the development of a more efficient and competitive ancillary services markets (e.g. reserves and/or frequency keeping). The HVDC link also improves competition in the wholesale market more generally.

6.4.14 These considerations mean beneficiaries are likely to change over time and objective identification of specific beneficiaries of the pole 3 upgrade may be difficult and problematic.

6.4.15 It is likely to be difficult to clearly and objectively identify beneficiaries of the HVDC link under a centrally-determined approach.

*HVDC capacity rights as means to identify beneficiaries*

6.4.16 The TPAG recognises that some of these difficulties may be resolved if some decision rights could be provided and a market based, rather than centrally determined (i.e. it would be outside of the Commerce Commission approval process), identification of beneficiaries was possible. The capacity rights approach initially suggested by NZIER could potentially achieve this.

6.4.17 Table 15 describes two possible capacity rights approaches. The merchant link option would be much simpler to implement and less costly to operate and administer (it avoids 2 or 3 solve processes and the need for continuous secondary trading<sup>52</sup>). This approach does not require 'users' or 'beneficiaries' of the HVDC to be identified each trading period.

6.4.18 The NZIER approach is likely to be more costly to implement and operate but it does identify 'users' of the HVDC. This is not necessary if capacity rights are auctioned or provided as part of a new investment agreement, however it may be necessary if capacity rights are allocated according to 'use'. Both of these options introduce possible complexities for Transpower, hedging, system security and market power.

6.4.19 Proponents of the capacity rights options point to a key benefit of the arrangement as being the identification of the beneficiaries of, and recovery of the costs for, the HVDC link through a market-based process<sup>53</sup>. They contend that it would provide a more transparent identification of beneficiaries and lead to less dispute and uncertainty about who should be funding the costs associated with the HVDC link.

***Risks from over or under allocating costs to beneficiaries***

6.4.20 Paragraphs 6.4.9 to 6.4.15 identified that any future investment in the HVDC link provides a mix of benefits to SI generators, SI customers, NI generators, and NI customers, and that allocating the benefits in an objective manner is difficult and problematic. As a result there is a high risk that some beneficiaries could be under-allocated cost and some beneficiaries could be over-allocated costs. If this is the case, there is the prospect that allocating costs to beneficiaries could contribute to poor investment decision-making rather than enhanced investment decision-making (for HVDC link investments).

6.4.21 Some grid-connected SI generators have suggested the recent pole 3 investment decision will create increased costs which exceed the private benefits likely to accrue to them.

<sup>52</sup> See "NZIER Capacity Rights Proposal – Implementation Issues", Electricity Authority 30 November 2010.

<sup>53</sup> Whether beneficiaries of the link are identified and pay the cost of the link depends on some extent on the capacity rights model used. The NZIER approach identifies 'users' rather than beneficiaries.

- 6.4.22 If the efficiency benefits associated with a beneficiary-pays approach are to be achieved, it is important that beneficiary allocations reflect the value to beneficiaries. The TPAG's analysis confirms this is difficult and controversial in the case of the HVDC link.

***Alignment between decisions rights and allocation of costs***

- 6.4.23 Section 4 pointed out that, ideally the beneficiaries of any investment in the HVDC link would be identified prior to any decisions being made; and they would have some decision-rights in the investment approval process. Under current arrangements investment decisions in respect of the HVDC link are made through a regulated process and beneficiaries have rights to make submissions, but not rights in respect of decision-making.

***Sunk costs***

- 6.4.24 The TPAG notes that the HVDC pole 3 upgrade is now committed. Any investment efficiency benefits from applying a beneficiary pays approach will relate to any further HVDC investments. Future investments in the HVDC link, apart from a possible second cable for pole 3, are probably 20-30 years in the future.
- 6.4.25 In the short term the investment efficiency benefits from applying a beneficiary pays approach to HVDC allocation are likely to be relatively small.

***Quantifying possible efficiency gains from beneficiary-pays***

- 6.4.26 It is difficult to quantify the possible benefits from the application of a beneficiary pays approach to the HVDC link because it involves subjective judgements about:
- a) how robust the investment decision-making process would be without beneficiary-pays;
  - b) the incentives applying to, and the capability of, the various beneficiaries of the HVDC transmission engaging in the decision-making process because of the application of a beneficiary pays approach; and
  - c) the extent to which the decision-making process enhanced by a beneficiary pays approach might create value by modifying HVDC investments decisions.
- 6.4.27 Nevertheless, it is helpful to consider some possible examples that might apply to the HVDC link. The following examples are an attempt to identify the minimum level of efficiency gains necessary to achieve NPVs resulting from the application of a beneficiary pays approach in the order of \$10-\$50m<sup>54</sup>. Some possible examples are:
- a) A reduction in investment costs of \$65m to \$350m (15% to 70% of a possible \$450m replacement of pole 2) in 25 years time is equivalent to \$10-\$50m NPV in 2011 at a 8% real pre tax discount rate.
  - b) Efficiency gains of up to \$10-\$45m NPV could be achieved if the optimal timing of investment in a second undersea cable costing \$125m<sup>55</sup> was varied 2 years from 2019 to 2021, or 15 years from 2019 to 2033 as a result of more accurate information on the extent and cost of

<sup>54</sup> The range of generation investment inefficiencies identified in Table 11.

<sup>55</sup> Transpower advise that they may consider submitting a proposal to extend the capacity of the HVDC to 1400MW by adding an additional undersea cable and filters. Transpower notes that the timing will be assessed following completion of the Pole 3 project and will depend on the costs and benefits which have not yet been assessed. However for budgeting purposes they are using an indicative nominal capital cost of \$151m in 2019 or \$125m expressed in 2011 dollar terms.



existing SI generation peak upgrade options. Note that the calculation used to illustrate this is simply the value from deferring the capital expenditure. This is an upper bound on the net benefit as any delay in such an investment will be offset by the loss of benefits from an earlier commissioning. As a general rule the net costs of moving away from an optimal timing will follow a 'bath-tub' curve, which may be relatively flat for small variations around the optimum. If this was the case the upper bounds estimated here could be significant over-estimates.

- 6.4.28 Achieving a \$10m NPV gain would seem possible provided parties paying are beneficiaries and are not charged more than the value obtained. Achieving \$50m NPV seems implausible as it implies that access to better private information would result in a 70% lower cost for a pole 2 replacement or greater than a 15 year movement in the optimal timing for an additional undersea cable.
- 6.4.29 It is important to recognise that, if the beneficiaries are not correctly identified, or the costs are allocated in a manner that fails to reflect the value to the beneficiaries, then outcomes could be worse and potentially net negative under a beneficiary-pays approach. In this case investment might be too small or too late, resulting in costs of the same order of magnitude as the benefits.
- 6.4.30 The benefits from a more durable HVDC pricing methodology are also difficult to quantify. However, if beneficiaries can be robustly and objectively identified in a way that is cost-effective, there could be reduced disputes or interventions, leading to lower on-going costs to participants. On the other hand, the analysis in paragraphs 6.4.9 to 6.4.15 suggests that identification of beneficiaries is complex and likely to be subject to on-going controversy. Similarly, it is difficult to quantify the benefits from the greater certainty that may result from the application of a beneficiary-pays approach.

#### **Assessment of the options relative to the status quo**

- 6.4.31 Assessing the merits of the various HVDC cost allocation options against the beneficiary-pays approach, relative to the status quo, is a matter of judgement, and the TPAG members have made different judgements about the issues raised in this section.
- 6.4.32 The status quo allocates the HVDC costs entirely to the grid-connected SI generation stations. While the TPAG members agree that SI generators are one of the beneficiary groups, there are varying views on whether other beneficiary groups should be allocated HVDC costs and whether the allocation to the SI generation stations leads to investment efficiency gains through participation in investment decision making. Although SI generators may have incentives to participate strongly in the investment decision-making process, they may not have incentives to seek the most efficient solution for the long term benefit of consumers.
- 6.4.33 Table 20 assesses whether each option applies a beneficiary pays approach and how each option compares with the status quo.

**Table 20 Application of efficiency consideration 1: beneficiary pays (HVDC options)**

Option	Application of the beneficiary pays approach, assessment relative to status quo
<b>HVDC capacity rights</b>	<p>Capacity rights approaches should lead to a market-based identification of and allocation of costs to beneficiaries, although the NZIER approach involves identification of ‘users’.</p> <p>Capacity rights should more clearly and objectively identify beneficiaries compared to the status quo, resulting in reduced likelihood of disputes.</p>
<b>MWh allocation</b>	<p>The MWh allocation retains the allocation to grid-connected SI generation stations. Application of the beneficiary pays approach therefore has the same strengths and weaknesses as the status quo.</p> <p>Grid-connected SI generators retain incentives to be involved in the investment planning process but durability may be a problem, and they may have incentives to delay investments past the point at which it is economic to do so if their costs exceed the private benefit.</p>
<b>Incentive-free allocation to SI generators</b>	<p>The incentive-free allocation to SI generators retains the charge on existing grid-connected SI generation, but removes it from new generation.</p> <p>Application of the beneficiary pays approach is similar to that of the status quo but may lead to increased disputes and uncertainty if new generators are not charged.</p> <p>SI generators remain incentivised to be involved in the investment planning process if new investment in HVDC is charged under the incentive-free allocation.</p>
<b>Postage stamp</b>	<p>The postage stamp option, by design, smears costs across customers and so does not apply a beneficiary pays approach except in the broadest of senses. It is unclear whether this option improves decision making as different end-users face different incentives to provide accurate information to the decision makers.</p> <p>There may be an ongoing prospect for disputes (as in the status quo).</p>
<b>Postage stamp transition</b>	<p>The application of the beneficiary pays approach for this option is similar to the postage stamp option in respect to improved decision making.</p>

**Efficiency consideration 2: Locational price signalling**

- 6.4.34 Locational price signalling can promote more efficient coordination of investment in and use of transmission, generation and DSM or more efficient trade offs between the costs and benefits of reliability as set out in section 4.
- 6.4.35 The stage 2 analysis of the benefits of locational signalling for economic transmission investments concluded that additional locational signalling of economic transmission investments is not justified.
- 6.4.36 The current HVDC cost allocation provides an additional locational signal which discourages new SI investment in favour of NI investment in the period following pole 3, even though such SI investment can be readily accommodated within the link capacity.

- 6.4.37 The analysis of the impact of the locational signal of the current cost allocation is set out in section 6.2 and estimates that the signal gives rise to possible generation investment inefficiencies of between \$14m and \$51m NPV over the next 30 years.
- 6.4.38 The MWh allocation to SI generators maintains the current locational price signal. The postage stamp, postage stamp transition and 'incentive free' options remove the locational signal. The capacity rights option would build in a different but potentially more refined locational signal.
- 6.4.39 The table below compares the locational signal provided by the options with that of the status quo. The case for maintaining the signal depends on whether the costs in terms of generation investment inefficiencies can be offset by the benefits of locational price signalling.

**Table 21 Application of efficiency consideration 2: locational price signalling to HVDC options**

	Assessment relative to status quo
<b>HVDC capacity rights</b>	Involves a locational signal which could be more refined than the existing signal, but the impact of the locational signal has not been assessed by the TPAG.
<b>MWh allocation</b>	Maintains the status quo locational signal to SI generation, but the signal is more favourable towards investment in, and dispatch of, peaking generation than the HAMI-based cost allocation.
<b>Incentive-free allocation to SI generators</b>	No locational signal (removes the locational signal provided by the status quo).
<b>Postage stamp</b>	No locational signal (removes the locational signal provided by the status quo).
<b>Postage stamp transition</b>	No locational signal (removes the locational signal provided by the status quo).

### Efficiency consideration 3: Unintended efficiency impacts

- 6.4.40 Transmission pricing methodologies have the potential to involve unintended efficiency impacts. The unintended efficiency impacts relevant to the HVDC are:
- Generation investment efficiency impacts
  - Peaker investment efficiency impacts
  - Dispatch efficiency impacts
  - Allocative efficiency impacts
- 6.4.41 Section 6.2 considered evidence of the first three of these inefficiencies in the status quo TPM.
- 6.4.42 The analysis set out in section 6.2 led the TPAG to conclude that there was sufficient evidence of potential efficiency gains from alternative options to warrant further analysis of these options.
- 6.4.43 The postage stamp, postage stamp transition and 'incentive free' options would entirely avoid the generation investment, peaker investment and dispatch inefficiencies associated with the status quo. The MWh option would avoid the peaker investment and dispatch inefficiencies and some portion of the generation investment inefficiencies associated with the status quo.

- 6.4.44 Table 23, which summarises the TPAG’s assessment of the options against the unintended efficiency impacts consideration, draws on the section 6.2 analysis for the generation and peaker investment efficiency impacts and dispatch efficiency impacts for the postage stamp, postage stamp transition and ‘incentive free’ options. It also draws on the analysis for the peaker investment and dispatch efficiency impacts for the MWh option.
- 6.4.45 TPAG has undertaken some further analysis for this section in order to assess the generation investment efficiency impacts for the MWh allocation and the allocative efficiency impacts for all four of these HVDC options. It has not considered the unintended efficiency impacts for capacity rights in detail as this would be significantly more complex.

#### Generation investment efficiency analysis for MWh allocation

- 6.4.46 The investment inefficiency analysis with respect to the status quo has been repeated using a MWh allocation to SI generators<sup>56</sup> and is also set out in Appendix D, section D.5. The results are summarised in Table 22 which confirms that the economic inefficiency is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh charge rather than HAMI.

**Table 22 Generation Investment Inefficiency of HAMI and MWh HVDC charges**

HVDC rental allocation	HVDC cost allocation and net incremental cost	Economic cost NPV \$m
SI generators continue to get HVDC rentals	\$35/kW/yr HAMI	\$14-51m (average \$31m)
	\$7/MWh	\$9-33m (average \$20m)
SI generators don’t get HVDC rentals	\$40/kW HAMI	\$19-64m (average \$38m)
	\$8/MWh	\$10-36m (average \$26m)

- 6.4.47 The analysis suggests that the potential generation investment inefficiency would fall by around \$10m to \$12m on average, if the existing HVDC charge remained on grid-connected SI generators but was allocated proportionately to generation in MWh rather than HAMI.
- 6.4.48 Although a MWh allocation to SI generators would reduce the generation investment inefficiency, an inefficiency of between \$9m and \$33m (average \$20m) would remain if SI generators continue to receive HVDC rentals and between \$10m and \$36m (average \$26m) if they don’t.

#### Allocative efficiency

- 6.4.49 If the HVDC costs were postage stamped to offtake customers, then RCPD transmission prices to those customers would increase by \$24/kW. Offtake customers would receive HVDC rentals (or potentially FTR residuals). End-use customers would likely see an average increase in delivered energy prices of approximately \$3/MWh<sup>57</sup>. Other forms of postage stamping (such as recovery

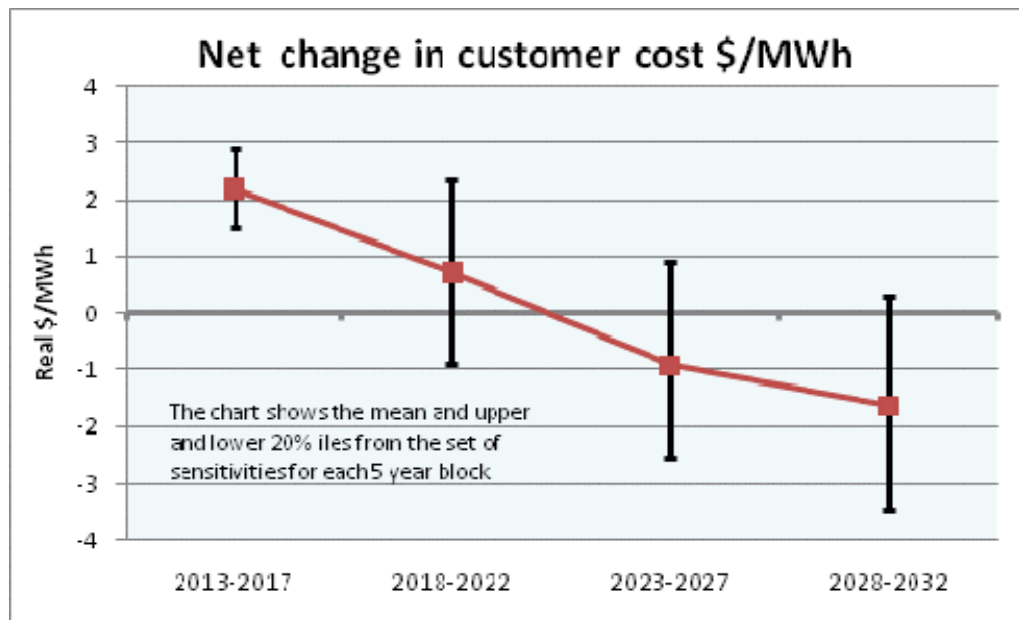
<sup>56</sup> Note that the net cost of a \$8/MWh HVDC charge would be around \$7/MWh if SI generators continue to receive the value of HVDC rentals.

<sup>57</sup> This is estimated on the basis of \$147m real HVDC revenue requirement in 2013/14 minus \$14m expected HVDC rentals over total NZ off take demand of approximately 42,000GWh.

from all generators equally on the basis of MWh, or a 50:50 recovery from generators and customers) are likely to result in a similar short run increase in delivered energy prices<sup>58</sup>.

- 6.4.50 The price increase from postage stamping HVDC charges to customers would be immediate and certain, but should be offset by a fall in wholesale prices in the medium term, as market prices adapt to a \$4-11/MWh drop in SI generation LRM. The timing and uncertainty in the reduction in the LRM is assessed in Appendix D, section D.8. The possible net effect over time is illustrated in Figure 2<sup>59</sup>.
- 6.4.51 If prices were to rise by \$3/MWh without any countervailing drop in wholesale prices there could be an allocative deadweight loss<sup>60</sup>, associated with the price increase, estimated as \$0.3m/yr<sup>61</sup> or \$2.5m net present value. However, analysis shows that there would likely be a countervailing drop in wholesale prices over time. If the transition is similar to that outlined in Figure 2 the deadweight loss would be reduced to \$1m. Under a postage stamp transition option, where grid connected SI generators continue to pay a portion and a price increase to customers is avoided, this deadweight loss would be reduced further or removed altogether.

**Figure 2 Possible impact of a move to postage stamping HVDC charges**



<sup>58</sup> If HVDC charges are allocated to all generators on a MWh basis then the effect of this is likely to flow directly through into higher wholesale prices. Similarly a 50:50 split between generators and customers would result in similar total \$3/MWh increase, half coming from higher wholesale prices and half from higher interconnection prices.

<sup>59</sup> This chart has been developed on the assumption that reductions in the LRM curve will flow through into average NZ wholesale prices over time. It is recognised that the exact timing and distribution between islands will vary according to supply and demand and competitive market dynamics.

<sup>60</sup> In economics, a deadweight loss (also known as excess burden or allocative inefficiency) is the net loss in economic welfare that is caused by a tariff or other source of inefficiency.

<sup>61</sup> \$3/MWh represents a 2% increase in the national average delivered electricity price of \$162/MWh (MED 2009) which would reduce demand by 0.4% or 220GWh assuming elasticity of -0.26 (which was used in the CBA for the Managing Locational Risk proposal). The deadweight loss =  $\$3 \times 220 / 2 = \$340,000/\text{yr}$ .

- 6.4.52 Deadweight losses may also be offset if there are efficiency gains from higher RCPD charges deferring transmission reliability investments<sup>62</sup>.
- 6.4.53 The table below summarises the unintended efficiency impacts for the HVDC options relative to the status quo.

**Table 23 Application of efficiency consideration 3: unintended efficiency impacts**

	Assessment relative to status quo
<b>HVDC capacity rights</b>	<p><b>Generation investment, peaker investment and allocative efficiency</b> – An analysis of the unintended efficiency impacts for capacity rights would be complex and the TPAG has not undertaken this analysis. It is possible that capacity rights could either reduce or increase the generation investment, peaker investment and allocative efficiency effects relative to the status quo.</p> <p><b>Dispatch efficiency</b> – The TPAG has not analysed dispatch efficiency under a capacity rights option but there might be short term productive inefficiencies due to the ability to constrain capacity on the HVDC link.</p>
<b>MWh allocation</b>	<p><b>Generation investment</b> – Would reduce the possible generation investment inefficiency from the disincentive to invest in SI generation (+\$10m to \$12m).</p> <p><b>Peaker investment</b> – Would avoid penalising peak injections so avoid discouraging investment in peak generation (+0 to \$37m).</p> <p><b>Dispatch efficiency</b> – Would avoid penalising peak injections so reduces incentives to withhold offers of short-term generating capacity in the SI (+\$0 to \$10m) However this benefit could be offset by different dispatch distortions arising from a per-MWh allocation. While there is no significant thermal generation in the SI, the MWh charge may result in slightly higher hydro spill. An experiment using the SDDP model<sup>63</sup> showed that the cost of this is relatively small (of the order of \$1 to 5m NPV over 5 years). This dispatch inefficiency could be significantly greater in the future if new base load or mid merit thermal was constructed in the SI.</p> <p><b>Allocative efficiency</b> – no change from the status quo.</p>
<b>Incentive-free allocation to SI generators</b>	<p><b>Generation investment</b> – Would eliminate the possible generation investment inefficiency in the status quo by recovering costs from grid-connected SI generators using an ‘incentive free’ allocation, although it might introduce other incentives on existing SI generators to avoid costs depending on the design of the allocation. (+14m to \$51m)</p> <p><b>Peaker investment</b> – Would eliminate the possible peak investment inefficiency of the status quo. (+0 to \$37m)</p> <p><b>Dispatch efficiency</b> – Would eliminate the possible dispatch inefficiencies of the status quo. (+\$0 to \$10m)</p> <p><b>Allocative efficiency</b> – No allocative efficiency effects.</p>

<sup>62</sup> This potential efficiency gain has not been estimated, but would involve an assessment of the size of the additional price signal to encourage demand management relative to the value of delaying transmission reliability investments. If the signal from the current RCPD charges is too low then there would be benefit from an increase. However if the signal from the current charges is approximately correct then there would be no additional benefit. In this case it may be sensible to recover HVDC charges from customers via a MWh rather than RCPD charge to avoid providing an excessive signal to manage peak demand.

<sup>63</sup> See section 5 of Appendix 4 to the Electricity Commission’s Transmission Pricing Review: Stage 2 Options, July 2010.

	Assessment relative to status quo
<b>Postage stamp</b>	<p><b>Generation investment</b> – Would eliminate the possible generation investment inefficiency by recovering costs from offtake. (+14m to \$51m)</p> <p><b>Peaker investment</b> – Would eliminate the possible peak investment inefficiency of the status quo. (+0 to \$37m)</p> <p><b>Dispatch efficiency</b> – Would eliminate the possible dispatch inefficiencies of the status quo. (+\$0 to \$10m)</p> <p><b>Allocative efficiency</b> – - \$2m to - \$1m</p>
<b>Postage stamp transition</b>	<p><b>Generation investment</b> – Would eliminate the possible generation investment inefficiency by recovering costs load (+14m to \$51m)</p> <p><b>Peaker investment</b> – Would eliminate the possible peak investment inefficiency of the status quo (+0 to \$37m)</p> <p><b>Dispatch efficiency</b> – would eliminate the possible dispatch inefficiencies of the status quo (+\$0 to \$10m)</p> <p><b>Allocative efficiency</b> – - \$1m to - \$0.1m</p>

#### Efficiency consideration 4: Competitive neutrality

- 6.4.54 There are a number of risks and issues relating to competitive neutrality for the allocation of HVDC costs. Competitive neutrality investment issues potentially occur:
- between NI and SI generation;
  - between large incumbent and other SI generators; and
  - between different technologies.
- 6.4.55 The benefits of these three competitive neutrality issues have also been included in the assessment of unintended efficiency impacts above.
- 6.4.56 There is also an emerging competition issue if the inter-island FTR proposal is accepted and rentals or auction proceeds are allocated to auction participants. The capacity rights option could introduce further competitive neutrality issues with the introduction of a new market.
- 6.4.57 Table 24 below assesses the competitive neutrality of the HVDC options relative to the status quo.

**Table 24 Application of efficiency consideration 4: competitive neutrality (HVDC options)**

	Assessment relative to status quo
<b>HVDC capacity rights</b>	Facilitates market-based commercial grid investment.. Introduces potential market power issues from rights to restrict HVDC capacity.
<b>MWh allocation</b>	Would reduce the competitive disadvantage to new SI peaker and mid capacity factor generation (wind and hydro).
<b>Incentive-free allocation to SI generators</b>	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI.

<b>Postage stamp</b>	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI. Reduces a competitive issue arising from the FTR proposal.
<b>Postage stamp transition</b>	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI.  Reduces a competitive issue arising from the FTR proposal.

### Efficiency consideration 5: Implementation and operating costs

6.4.58 The implementation and operating costs, relative to the status quo are considered in the table below.

**Table 25 Application of efficiency consideration 5: implementation and operating costs (HVDC options)**

	Assessment relative to status quo
<b>HVDC capacity rights</b>	Involve significant changes to the market clearing software and settlements systems and potentially require the development of associated auctions and secondary trading markets. These options represent relatively significant changes to the current market arrangements which are likely to involve high setup and operating costs for a central body and market participants. The options are not sufficiently well developed to estimate the costs with any precision, however significant modifications to the market clearing software are likely to cost tens of millions of dollars and the development of secondary markets could cost of the order of \$20 to \$40m NPV if the proposed FTR market is taken as a guide. Would require several years to design and implement.
<b>MWh allocation</b>	Could be quickly implemented at low cost and would involve similar operating costs to the status quo. An estimate of the costs might be \$1m.
<b>'Incentive-free' allocation to SI generators</b>	It is unlikely that this option could be implemented in a way that is workable long term and did not lead to immediate disputes unless used as a transition arrangement.
<b>Postage stamp</b>	Could be quickly implemented at low cost and would involve similar operating costs to the status quo. An estimate of the costs might be \$1m.
<b>Postage stamp transition</b>	The postage stamp element of this option could be quickly implemented at low cost and have operating costs similar to the status quo. Setting up the transition arrangement potentially involves a larger cost. An estimate of the costs might be \$2m.

### Efficiency consideration 6: Good regulatory practice

6.4.59 As set out in section 4, good regulatory practice is made up of a number of components. This is true as a general statement and in the context of the TPM. The discussion in this section particularly considers possible wealth transfers and step changes in prices. It goes on to briefly



consider whether there are differences between HVDC and AC assets that are pertinent to transmission pricing as this is relevant when considering the need for consistency over all assets. Table 26 at the conclusion of the section addresses all identified elements of good regulatory practice.

***Wealth transfers and step changes in prices***

- 6.4.60 The TPAG has approached the question of wealth transfers and step changes in prices from the perspective that any changes that result in wealth transfers should be justified by significant efficiency benefits. Any proposed change should be an effective, efficient and proportionate response to the issue concerned. Where change involving a wealth transfer is justified it should be well signalled in advance and a transition should be provided so participants have time to adjust.
- 6.4.61 The TPAG expects there would be small wealth transfers between generators from a change to a MWh allocation, but there would be more substantial short term wealth transfers from consumers to SI generators under a change to postage stamping. The likelihood of wealth transfers is not as clear for the capacity rights options and has not been investigated by the TPAG.
- 6.4.62 Paragraphs 6.4.49 and 6.4.50 described the short run increase in delivered energy prices from postage stamping HVDC charges.
- 6.4.63 Were there to be a change to postage stamping HVDC charges, the extent and size of the overall value changes in the sector are difficult to estimate with any precision because of the offsetting impacts of efficiency gains. The trends in the value changes are however likely to be as follows:
- SI generators: lower transmission costs offset by lower medium term wholesale prices may mean a value change to them that is net positive or negative in medium term;
  - NI generators: lower medium term wholesale prices are likely to mean a value change to them that is net negative;
  - SI customers: higher transmission costs offset by lower medium term SI wholesale prices (reflecting lower long run marginal cost of SI generation) could mean a value change to them that is net negative or positive in medium term;
  - NI customers: higher transmission costs offset by lower medium term NI wholesale prices (also reflecting, although not so directly, the lower long run marginal cost of SI generation) is likely to mean a value change to them of net zero or negative.
- 6.4.64 While medium term value impacts are likely to be relatively small, it is recognised that postage stamping results in a significant immediate and certain transfer of value to SI generators from NZ customers offset by future and uncertain wholesale price reductions compared to what otherwise might be expected.
- 6.4.65 As noted above (6.4.60) consistency and stability in pricing is important and changes which involve wealth transfers should be avoided unless there are significant efficiency benefits. The magnitude of the value shifts and potential price changes, which would result from postage stamping HVDC charges, need to be seen in the context of other changes in the market. For example increases in transmission charges arising from the major AC grid investments are likely to be of the order of \$4/MWh<sup>64</sup>.

<sup>64</sup> The total HVAC revenue recovery is expected to increase \$225m from \$540m in 2010 to \$765m in 2016 (in real 2011 dollar terms). This represents a real increase in the average HVAC charges of \$4/MWh.

- 6.4.66 There are a range of views within the TPAG as to whether the benefit of removing the generation investment and dispatch inefficiency is significant enough to justify a move to full postage stamping with its short run value impacts. The TPAG has developed a transitional option which eliminates the residual inefficiencies and minimises the value impacts.
- 6.4.67 A transitional approach to postage stamping HVDC charges which retains the historical allocation of HVDC costs to grid-connected SI generators in the short term but moves to full postage stamping over a period of time would avoid an immediate transfer of value to SI generators. The proposition would be that by the time full postage stamping was introduced, the wholesale price effects would be achieved.

***Consistency over the whole grid.***

- 6.4.68 The TPAG has considered whether there are material differences between the HVDC and AC assets relevant to the efficiency considerations. Some of the TPAG members consider that the HVDC is dispatchable and that this makes the HVDC different from other assets but this was not the majority view. Although the HVDC is DC rather than AC it is not significantly different to the interconnection assets between the 17 other regions in the NZ grid. Flows on both the DC and other AC assets are effectively controlled by Scheduling Pricing and Dispatch (SPD) software scheduling generation offers to meet demand while accounting for the constraints and losses on all transmission links. SPD does not distinguish between DC and AC assets. If the proposition that AC and DC are treated in the same manner is accepted it implies that the pricing approach for DC assets should be generally consistent with the approach for AC interconnection assets.
- 6.4.69 This does not mean the costs of the DC assets cannot be allocated in a different manner from the AC assets if there is an efficiency justification to do so. (For example if beneficiaries and their share of costs could be readily identified for HVDC assets but not for AC assets.) Similarly, it does not mean the costs of AC assets cannot be allocated in a different manner to other AC assets if there is an efficiency justification to do so.

Table 26 Application of efficiency consideration 6: good regulatory practice (HVDC options)

	Assessment relative to status quo
<b>HVDC capacity rights</b>	<p><b>Consistency between regulators</b> - Would not be inconsistent with Commerce Commission decision making.</p> <p><b>Durability</b> – It is uncertain whether a capacity rights approach would be durable. It is likely to depend on the uptake by and impact on the market. Possible revenue risk or shortfall for Transpower may make capacity rights approach unstable. Australian experience has seen merchant links converted to regulated status over time (see footnote 44).</p> <p>On the other hand where a capacity rights approach enabled more robust identification of beneficiaries and charges, it may significantly reduce the likelihood of disputes.</p> <p><b>Consistency over time</b> - Investments in generation and demand have been made on the basis of open access and it would be poor regulatory practice to move away from this approach for an existing transmission asset unless there were significant efficiency benefits. However once implemented capacity rights would provide consistency going forward.</p> <p><b>Consistency over the whole grid</b> – Would not be consistent with treatment of other transmission assets at this time but it may introduce an approach that could have useful applications on other transmission links.</p> <p><b>Wealth transfers and step changes in prices</b> – Possible wealth transfers and step changes in prices are unknown.</p> <p><b>Market fit</b> – It would be a move away from the current open access framework. On the other hand it may introduce an approach that could have useful applications on other transmission links. A capacity rights approach discovers who values the HVDC assets and the value they would be willing to pay so is consistent with a market-based approach.</p>
<b>MWh allocation</b>	<p><b>Consistency between regulators</b> – Would not be inconsistent with Commerce Commission decision making.</p> <p><b>Durability</b> – Retaining the 100% allocation to SI generation leaves some generation inefficiencies and potential competitive advantage to Meridian. This would make it subject to ongoing debate as it is arguably inconsistent with the beneficiary pays approach as other significant beneficiaries are not charged and the approach is not being applied to other interconnection links for which beneficiaries can be more objectively determined.</p> <p><b>Consistency over time</b> – Would be consistent over time provided was not subject to ongoing review.</p> <p><b>Consistency over the whole grid</b> – Would retain the inconsistency contained in the status quo.</p> <p><b>Wealth transfers and step changes in prices</b> – May involve a small wealth transfer between generators but there would be no step changes in prices.</p> <p><b>Market fit</b> – Similar to the status quo in that retains distinction between DC and AC assets.</p>

	Assessment relative to status quo
<b>Incentive-free allocation to SI generators</b>	<p><b>Consistency between regulators</b> – Would not be inconsistent with Commerce Commission decision making.</p> <p><b>Durability</b> – Likely to be disputed immediately as an arbitrary allocation of costs to a group of participants.</p> <p><b>Consistency over time</b> – Involves a significant change from the status quo creating an inconsistency over time. However, once implemented would be consistent going forward.</p> <p><b>Consistency over the whole grid</b> – This charging methodology would be applied only to the HVDC assets and would not be consistent with the allocation of other costs.</p> <p><b>Wealth transfers and step changes in prices</b> – There would be no wealth transfers and step changes in prices (as for the status quo)</p> <p><b>Market fit</b> – Similar to the status quo.</p>
<b>Postage stamp</b>	<p><b>Consistency between regulators</b> - Would not be inconsistent with Commerce Commission decision making.</p> <p><b>Durability</b> – As with the status quo this option may be subject to disputes, lobbying and intervention. In this case because of the short term wealth transfer and immediate step change in prices.</p> <p><b>Consistency over time</b> – Involves a significant change from the status quo creating an inconsistency over time. However, once implemented would be consistent going forward.</p> <p><b>Consistency over the whole grid</b> – Is more consistent than status quo as it treats DC and AC interconnection assets in the same manner.</p> <p><b>Wealth transfers and step changes in prices</b> – Value shift in transition is inconsistent with good regulatory practice.</p> <p><b>Market fit</b> – Similar to the status quo.</p>

	Assessment relative to status quo
<b>Postage stamp transition</b>	<p><b>Consistency between regulators</b> - Would not be inconsistent with Commerce Commission decision making.</p> <p><b>Durability</b> – Where the transition smoothes out wealth transfers and step changes in prices may be less open to disputes than status quo because addresses current inefficiencies (as identified in this paper) and perceived inequities. However, participants may challenge because of the potential for a value transfer in the event that the future and uncertain wholesale price effects are not realised.</p> <p><b>Consistency over time</b> – Involves a change from the status quo creating an inconsistency over time. However once implemented would set out a clear transition path going forward and once fully transitioned would be consistent going forward.</p> <p><b>Consistency over the whole grid</b> - Is more consistent than status quo as it treats DC and AC interconnection assets in the same manner.</p> <p><b>Wealth transfers and step changes in prices</b> – Where the transition smoothes out wealth transfers and step changes in prices could be similar to the status quo. The transition path could minimise the risk and extent of potential net price rises to end-use customers to less than 1%. It is possible to design a transition that has no step increases in prices.</p> <p><b>Market fit</b> – Similar to the status quo but slightly better to the extent it treats AC and DC assets consistently.</p>

**Q7.** The TPAG has assessed the HVDC options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with and/or could provide further information on? Please provide details.

## 6.5 Assessment summary

6.5.1 Section 4 sets out the TPAG’s analysis framework which is based on the Authority’s statutory objective as it is applied by the CAPs.

6.5.2 The Authority will ultimately need to address the following questions:

- a) Is there a potential Code amendment which would result in a net improvement (efficiency gain) for the long term benefit of consumers?
- b) Have the correct options been identified?
- c) Have the costs and benefits of each option been correctly identified? What is the net benefit identified from each option and level of confidence that this will be captured?
- d) Which option has the highest combined net benefit associated with the highest likelihood of capturing the benefit?

6.5.3 This section:

- revisits whether there is an efficiency gain for the long term benefit of consumers in light of the application of the efficiency considerations to the options (CAP 2); and

- compares the costs and benefits of the options in order to identify the option which has the highest combined net benefit with the highest likelihood of capturing the benefits and minimising the costs (CAP 3).

6.5.4 In section 6.2 TPAG members concluded that there was sufficient evidence of potential efficiency gains to warrant analysis of alternative options for the allocation of HVDC costs. TPAG members did not agree on whether there was sufficient evidence to justify a change from the status quo, rather there are two views:

- In the view of the minority, there is no clear and material efficiency gain to justify a change.
- In the view of the majority, there is a clear and material efficiency gain to justify a change.

6.5.5 This assessment summary first provides both the majority and minority view on the potential efficiency gains. It then provides a comparison of the alternatives as the majority view is that a change from the status quo is justified. Finally it sets out the majority conclusion that the TPAG's analysis suggests that a postage stamp transition has the highest combined net benefit of all the options, noting that in the view of the minority there is no clear material efficiency gain that justifies a change from the status quo.

6.5.6 The section concludes by elaborating on possible postage stamp transition options.

#### **Application of CAP 2 – clearly identified efficiency gain; regulatory or market failure?**

6.5.7 The TPAG has considered whether there is a possible efficiency gain for the long term benefit of consumers from changing the allocation or structure of the HVDC charges. It has also noted, but did not consider in detail, whether the status quo arrangements are a regulatory failure. There was no consideration of whether the status quo arrangements have created a market failure.

6.5.8 In the view of the majority of the TPAG members there is a clearly identified efficiency gain that would justify a change from the status quo arrangements. In the view of a minority of members, there is no clear efficiency gain and a change is not justified.

#### **Identification of possible efficiency gains for the long term benefit of consumers – majority view**

6.5.9 The TPAG's analysis as set out in section 6.2 and Appendix D identified an opportunity for an efficiency gain through restructuring the HVDC charge. The proposition is that the status quo arrangements whereby grid-connected SI generators pay for the HVDC leads to inefficiencies in generation investment, peaker investment, and dispatch resulting in higher end prices for consumers. Once implementation and operating costs of alternative options are taken into account the possible efficiency gains from the alternative options with the greatest efficiency gains lie in the range \$11m to \$96m NPV. (These figures would be approximately \$7m greater, if the generators do not receive the HVDC rentals). These efficiency gains should lead to reduced prices to end consumers compared to the status quo counterfactual.

6.5.10 The scenarios supporting these estimates of efficiency gains take into account a number of conservative assumptions. For example:

- much of the demand for new generation over the next 5-10 years is met from relatively cheap NI geothermal irrespective of the HVDC cost allocation;
- there is a larger contribution from NI wind compared to SI wind; and

- thermal generation is modelled as being more likely to be built in the NI should additional gas supply become available.
- 6.5.11 The sensitivity analysis performed also tests the inherent uncertainty in the costs of developing renewable wind, geothermal and hydro projects.
- 6.5.12 The generation investment inefficiencies above might be justified if they are offset by transmission investment efficiencies either through more efficient investment in AC assets or future DC assets. However this does not appear to be the case for the reasons set out in 6.5.13 (AC assets) and 6.5.14 (DC assets).
- 6.5.13 The stage 2 analysis of the benefits of locational signalling concluded that there were unlikely to be benefits in deferring economic transmission investments. Options to provide comprehensive locational signals for AC assets were therefore not pursued.
- 6.5.14 Charging SI generators for the HVDC is not likely to yield investment efficiencies through improved decision making for new HVDC investments because:
- there is no robust, cost-effective mechanism at this time to clearly and objectively determine the beneficiaries of the HVDC and their share of the benefits;
  - even if there are new regulated HVDC investments, SI generators that are allocated the full cost of the HVDC costs will not necessarily be correctly incentivised to lobby and provide improved information for the long term interests of all consumers; and
  - there may be alternative incentive-based regulation or other mechanisms for investment in HVDC in the future.
- 6.5.15 On this basis, the majority reached its conclusion that there is a clear and material efficiency gain that justifies a change from the status quo HVDC cost allocation.

#### **Alternative view – minority view**

- 6.5.16 The efficiency gains rely on some cheaper SI generation investment being brought forward ahead of more expensive NI generation as a result of the removal of the HVDC charge. This may not happen.
- 6.5.17 Project investment decisions are complex and involve numerous inputs. Investment decisions can be swayed by factors such as environmental consenting issues, company strategies and familiarity with particular technologies. Some of these factors are generic to all investors, some are company specific, and some can be locational in nature.
- 6.5.18 These factors can cause investments to be made (or not made). The HVDC charge is only one factor among many in the decision making of generator investors. The potential efficiency gains are not sufficient to justify a change from the status quo.
- 6.5.19 There may also be some scenarios in which there are no, or even fewer, cheaper SI generation options, delayed as a consequence of the HVDC charge.
- 6.5.20 In the view of the minority, the analysis does not adequately account for these factors and scenarios. On this basis, the minority reached its conclusion that there is no clear and material efficiency gain that justifies a change from the status quo HVDC cost allocation.

**Q8.** What is your position on the two views? Do you have further evidence to support either the majority or minority view?

**Majority view on the application of CAP 3 – assessment of options against efficiency considerations using the status quo as a counterfactual**

- 6.5.21 In the view of the majority, there is justification to change from the status quo arrangements and identify a preferred option. This section sets out the majority view on the comparison of the alternative transmission pricing options.
- 6.5.22 Based on its initial assessment that there was sufficient evidence of potential efficiency gains to warrant analysis of alternative options for the allocation of HVDC costs the TPAG identified and assessed a range of options based on stage 2 options and options proposed by submitters. The options have been described in section 5.3 and were:
- HVDC capacity rights
  - MWh allocation
  - ‘Incentive-free’ allocation to SI generators
  - Postage stamp
  - Postage stamp transition
- 6.5.23 Table 27 below summarises the assessment of the options against the efficiency considerations 1-6.
- 6.5.24 The dollar amounts are investment efficiency calculations based on the analysis set out in Appendix D. Positive values indicate an overall efficiency gain in total NPV terms relative to the status quo. Where it is not possible to quantify the benefits, a tick represents net benefits relative to the status quo and a cross represents a worsening relative to the status quo. Question marks indicate uncertainty around possible outcomes.
- 6.5.25 The table does not include the ‘incentive free’ allocation as it is considered by all to be unworkable and not durable other than as part of a transitional arrangement.



Table 27 Costs and benefits of the HVDC Options relative to the status quo (HAMI)

Efficiency consideration	MWh allocation	Postage stamp		Capacity rights options
		Full	Transition	
<b>3 Unintended efficiency impacts</b>				
1. Generation investment <sup>65</sup>	+\$10 to \$12m	+\$14 to +\$51m	+\$14 to +\$51m	?
2. Peaker investment <sup>66</sup>	+ \$0 to +\$37m	+\$0 to +\$37m	+\$0 to +\$37m	?
3. Dispatch efficiency	-\$5 to +\$9m <sup>67</sup>	+\$0 to +\$10m	+\$0 to +\$10m	X
4. Allocative efficiency	Same	-\$2 to -\$1m	-\$1 to -\$0.1m	?
<b>5 Implementation &amp; on-going costs</b>	-\$1m	-\$1m	-\$2m	-\$20-40m <sup>68</sup> ?
<b>Quantified benefit (NPV 30yr)<sup>69</sup></b>	<b>+\$4 to +\$57m</b>	<b>+\$11 to +\$96m</b>	<b>+\$11 to +\$96m</b>	<b>?</b>
<b>1 Beneficiary pays<sup>70</sup></b>	same	?	?	✓
<b>2 Locational Pricing<sup>71</sup></b>	✓	✓	✓	?
<b>4 Competitive neutrality<sup>72</sup></b>	same	✓✓	✓✓	✓X <sup>73</sup>
<b>6 Good Regulatory Practice</b>				
1. Consistency btw regulators	same	same	same	?
2. Durability <sup>74</sup>	?	?	? ✓	?
3. Consistency over time	same	XX	X	?
4. Consistency over grid	same	✓	✓	X?
5. Wealth transfers	minor	<i>small</i>	<i>none</i>	?
6. Price step changes	none	<i>moderate</i>	<i>none-low<sup>75</sup></i>	?
7. Market fit	same	✓	✓	X

<sup>65</sup> This investment inefficiency is in respect of base load and renewable “energy” generation options (not peaking) and would be approx \$7m higher if SI generators no longer receive the value of HVDC rentals.

<sup>66</sup> The uncertainty around these inefficiencies is explored in section D.9.

<sup>67</sup> This could be more negative if significantly more SI thermal generation is built and the MWh allocation results in a more significant dispatch distortion.

<sup>68</sup> The setup and transactions cost of the merchant link will be lower than the NZIER option.

<sup>69</sup> This is the NPV to 2011 over 30 years. Note that the upper and lower bounds are simply based on sum of the individual lower and upper bounds for each quantified aspect.

<sup>70</sup> The capacity rights option may lead to a market-based approach to identifying beneficiaries. It is unclear whether the other options better allocate costs to beneficiaries as it is difficult to clearly and objectively identify beneficiaries.

<sup>71</sup> The unintended efficiency impacts of changes in the locational signals are quantified above.

<sup>72</sup> The efficiency impacts of changes in competitive neutrality between NI and SI and technology type are included in the quantification of unintended efficiency impacts above. The efficiency impact of changes in competitive neutrality between SI generators is accounted for by using counterfactual 1 in the analysis. This could be an underestimate if the cost increasing dominance under other counterfactuals is greater than \$5-10m NPV.

<sup>73</sup> Tick for facilitating commercial grid investment, cross for potential market power issues from rights to restrict link capacity.

<sup>74</sup> There are durability issues for each option, including the status quo, all of which are hard to compare with those of the status quo. The Postage stamp transition should be more durable relative to postage stamp.

<sup>75</sup> It is possible to design a transition that has no step changes in prices or wealth transfers for customers as a group, but there may be small wealth transfers remaining.

### Postage stamp and postage stamp transition options

- 6.5.26 The analysis of the unintended efficiency impacts shows that there are efficiency gains to be made from alternatives to the status quo. The analysis was undertaken across a range of scenarios, tested using sensitivity analysis, and used a number of conservative assumptions for example, the level of cheaper NI geothermal resources and the level of NI wind resource.
- 6.5.27 The highest efficiency benefits are estimated at between \$11m and \$96m for either the full postage stamping or postage stamp transition options.
- 6.5.28 Both of these involve a change to the status quo practice of allocating all HVDC charges to grid-connected SI generators. Both represent a move to a more consistent approach over the grid, and may thus result in more durable arrangements with consequent benefits associated with greater regulatory certainty.
- 6.5.29 The full postage stamping scores poorly on good regulatory practice as it involves a significant immediate and certain transfer of value to SI generators from consumers offset by future expected wholesale price reductions compared to what otherwise might be expected. The postage stamp transition avoids or minimises these step changes in prices and wealth transfers.

### MWh allocation

- 6.5.30 The MWh option provides some of the efficiency gains captured by the postage stamp options. It does not involve the short term wealth transfer but also does not deliver the full generation investment efficiencies. However there are other uncertainties associated with this option.
- 6.5.31 Analysis shows there is an efficiency gain of \$4m - \$57m to be derived by retaining the allocation of the HVDC charge to SI generators, but changing the allocation mechanism to be by MWh instead of peak injection.
- 6.5.32 The most significant portion (\$0m-37m) of these benefits come from addressing concerns that the HAMI charge dis-incentivises the offering of existing peak capacity, the development of capacity enhancements to existing hydro plant and the development of intermittent generation with low capacity factors.
- 6.5.33 Although the MWh allocation removes the inefficiencies associated with the HAMI allocation it may introduce other dispatch inefficiencies. This will happen if, as a result of the HVDC charge, more expensive NI generators are dispatched ahead of SI generators. Under current market conditions this risk is small, but if there was significant thermal build in the SI, the risk increases.

### Capacity rights

- 6.5.34 The transaction and setup costs of the capacity rights options, whilst they have not been closely examined, are likely to be of a similar order of magnitude to the benefits of reducing some of the pricing inefficiencies in the status quo. While capacity rights enables market based identification of the beneficiaries of HVDC capacity rights, the benefits of this are uncertain and there are a number of issues that would need to be resolved before it could be considered a workable option. The TPAG has concluded that at this time the costs of introducing a capacity rights approach outweigh the benefits. Capacity rights has the potential to provide an opportunity to identify beneficiaries of the DC but also across the grid. It would also involve the establishment of new markets. This makes a move to capacity rights a market design issue which is not within the scope of the TPAG.

## 6.6 Majority conclusion

6.6.1 In the view of the majority the TPAG's analysis suggests that:

- the efficiency gains are greatest from applying either the postage stamp or postage stamp transition;
- the likelihood of capturing the efficiency gains from either the postage stamp or postage stamp transition is equivalent to the likelihood of capturing the benefits under MWh;
- postage stamping is likely to create an efficiency gain but it results in a significant immediate and certain transfer of value to SI generators offset by future and uncertain wholesale price effects;
- as for postage stamping, the postage stamp transition option is likely to create an efficiency gain, but does not involve immediate wealth transfers. This option has the highest combined net benefit of all the options – it will provide efficiency gains with the least likelihood of dis-benefits to consumers.

**Q9.** Do you agree with the summary of the comparison of alternative options and the majority conclusion that leads to the identification of the postage stamp transition option as the preferred option? If not, please give reasons why.

**Q10.** The TPAG's analysis assesses postage stamping the HVDC costs to offtake customers. In Table 17, the impact on the analysis of different postage stamp variants was considered. Do you think there are other variants of the postage stamp options that should be explored further? Please give reasons.

6.6.2 The next section provides more detailed elaboration of possible postage stamp transition options, given that this is the majority preferred option. The minority preferred option is to remain with the status quo which does not require further elaboration.

## 6.7 Possible transition options

6.7.1 A transitional approach which retains the historical allocation of HVDC costs to grid-connected SI generators, and moves to postage stamping over a period of time may have merit if there is a proposal to move from the current HVDC cost allocation to SI generators to a postage stamp cost allocation to offtake. This would be consistent with good regulatory practice which seeks to promote consistency and stability in pricing. It would also remove the generation investment inefficiencies associated with the status quo without creating significant value transfers.

6.7.2 The transition could be implemented by requiring existing grid-connected SI generating stations to continue to pay for a portion of the HVDC costs over a transition period, and to have the remaining costs recovered via postage stamp charges to customers. The portion recovered from SI generators would be phased out over a transitional period, and the allocation between existing SI generators would be fixed in advance (and allocated to specific generating stations) so as to remove any incentives that could distort behaviour and create inefficiencies. This could be done, for example, on the basis of historical share of HVDC charges.

6.7.3 The key transition parameters are:

- a) the initial HVDC charge to existing SI generators; and
- b) the length of the transition period to postage stamping.

- 6.7.4 The initial charge to existing SI generators could be:
- a) \$23/kW = the expected HVDC charge without pole 3<sup>76</sup> (50% of the total HVDC charge in 2013), or
  - b) \$30/kW = the total expected HVDC charge in 2013 minus the incremental capital recovery cost for pole 3 assets = (65% of the total HVDC charge), or
  - c) \$45/kW = close to the total expected HVDC charge in 2013
- 6.7.5 The length of the transition could be; short (5 years), medium (10yrs) or long (15 yrs).
- 6.7.6 The higher initial charge would be preferred to minimise step changes in prices and potential allocative loss, and the length of the transition could be set to minimise the value impact and to make an incentive free fixed allocation to existing SI generators workable.
- 6.7.7 As discussed in Appendix D, the potential competition issues in the proposed FTR auctions would be avoided if existing SI generators no longer receive their share of residual HVDC rentals. This could be implemented by allocating all the residual HVDC rentals to customers from 2013 and accounting for the value impact of this when setting the initial portion and length of the transition period. The expected value of the HVDC rentals from 2013 is uncertain, but is likely to be in the range of \$4-6/kW/yr<sup>77</sup>.
- 6.7.8 The table below shows the short run price impact and potential present value average price impact on end-use customers under the range of possible transition settings.

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<sup>76</sup> Note that this is based on an extrapolation of the trend in HVDC charges up to 2009.

<sup>77</sup> See Appendix C.13

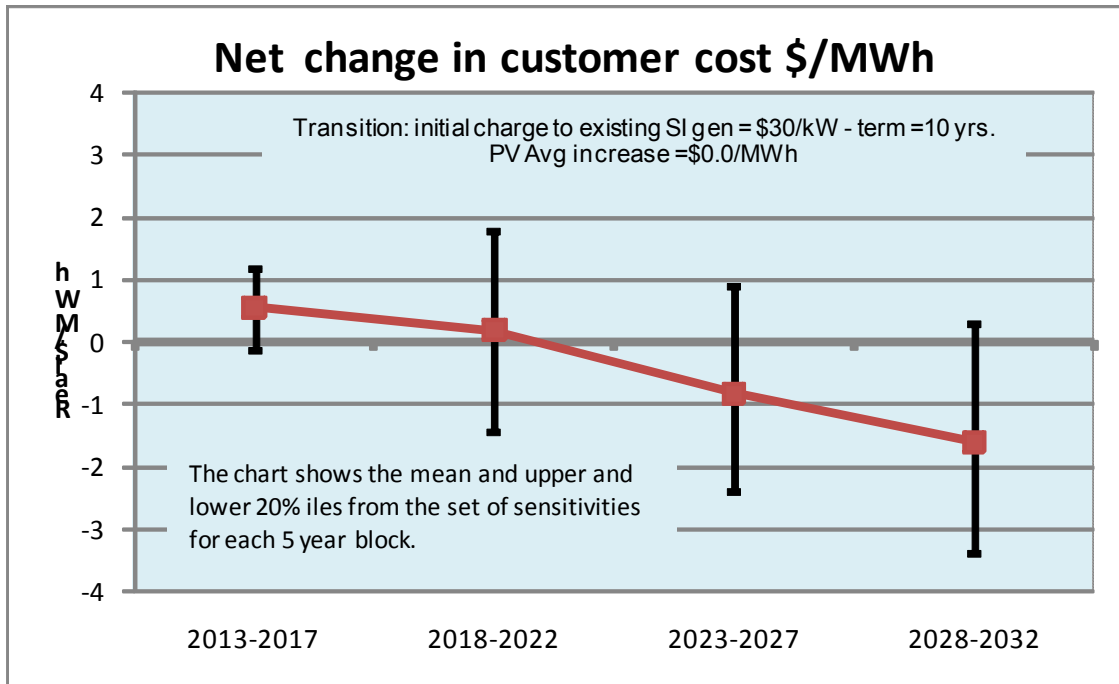
**Table 28 Impact on end-use customers under alternative transition options**

Transition Settings		Present Value Average Price Impact				
Initial charge to existing SI Gens	Transition length	Initial price increase to customers	Transmission Price increase	Value of HVDC rentals	Mean wholesale price reduction	Mean net price increase
\$/kW/yr	Years	\$/MWh	\$/MWh	\$/MWh	\$/MWh	\$/MWh
\$0	0	\$3.5	\$2.8	-\$0.4	-\$1.5	\$0.9
\$23	5	\$1.8	\$2.4	-\$0.4	-\$1.5	\$0.5
\$23	10	\$1.8	\$2.1	-\$0.4	-\$1.5	\$0.2
\$23	15	\$1.8	\$1.9	-\$0.4	-\$1.5	\$0.0
\$30	5	\$1.2	\$2.2	-\$0.4	-\$1.5	\$0.3
\$30	10	\$1.2	\$1.9	-\$0.4	-\$1.5	\$0.0
\$30	15	\$1.2	\$1.6	-\$0.4	-\$1.5	-\$0.3
\$45	5	\$0.1	\$1.9	-\$0.4	-\$1.5	\$0.0
\$45	10	\$0.1	\$1.4	-\$0.4	-\$1.5	-\$0.5
\$45	15	\$0.1	\$1.0	-\$0.4	-\$1.5	-\$0.9

- 6.7.9 The table shows that either a \$23/kW charge with a 15 year transition, a \$30/kW charge with a 10 year transition or a \$45/kW charge over a 5 year transition would leave end-use customers<sup>78</sup> no worse off than the status quo.
- 6.7.10 Of these the shortest transition might be preferred as this makes a fixed (incentive free) allocation of HVDC charges between existing SI generators more workable, and it also reduces the initial price impact to zero. A \$30/kW initial charge with a 10 year transition would also be a reasonable option as it would only have a \$1/MWh initial price impact and a smoother transition as it better matches the profile of the expected reduction in wholesale prices.
- 6.7.11 It is recognised that the higher transmission cost to customers is more certain whereas the potential offsetting wholesale price reduction is delayed and more uncertain. Figure 3 below illustrates this issue by showing the 20 and 80 percentile range for the potential impact on end-use customers under the \$30/kW option with a 10 year transition.

<sup>78</sup> Note that this table reports the impact on end-use customers as a whole. It is noted that the impact will vary between groups of customers. For example it is likely that SI end-use customers would be slightly better off than NI customers, since the wholesale price reduction should be greater in the SI, whereas the transmission cost increase would be uniform. Similarly base load customers whose contribution to the RCPD is relatively low would also be better off than the average since they would face a smaller transmission charge increase, but get the full benefit of wholesale price reductions. Note also that although the value impact on generators in total may be small, it will vary between groups.

Figure 3 The potential net impact on customers of a \$30/kW 10 year transition

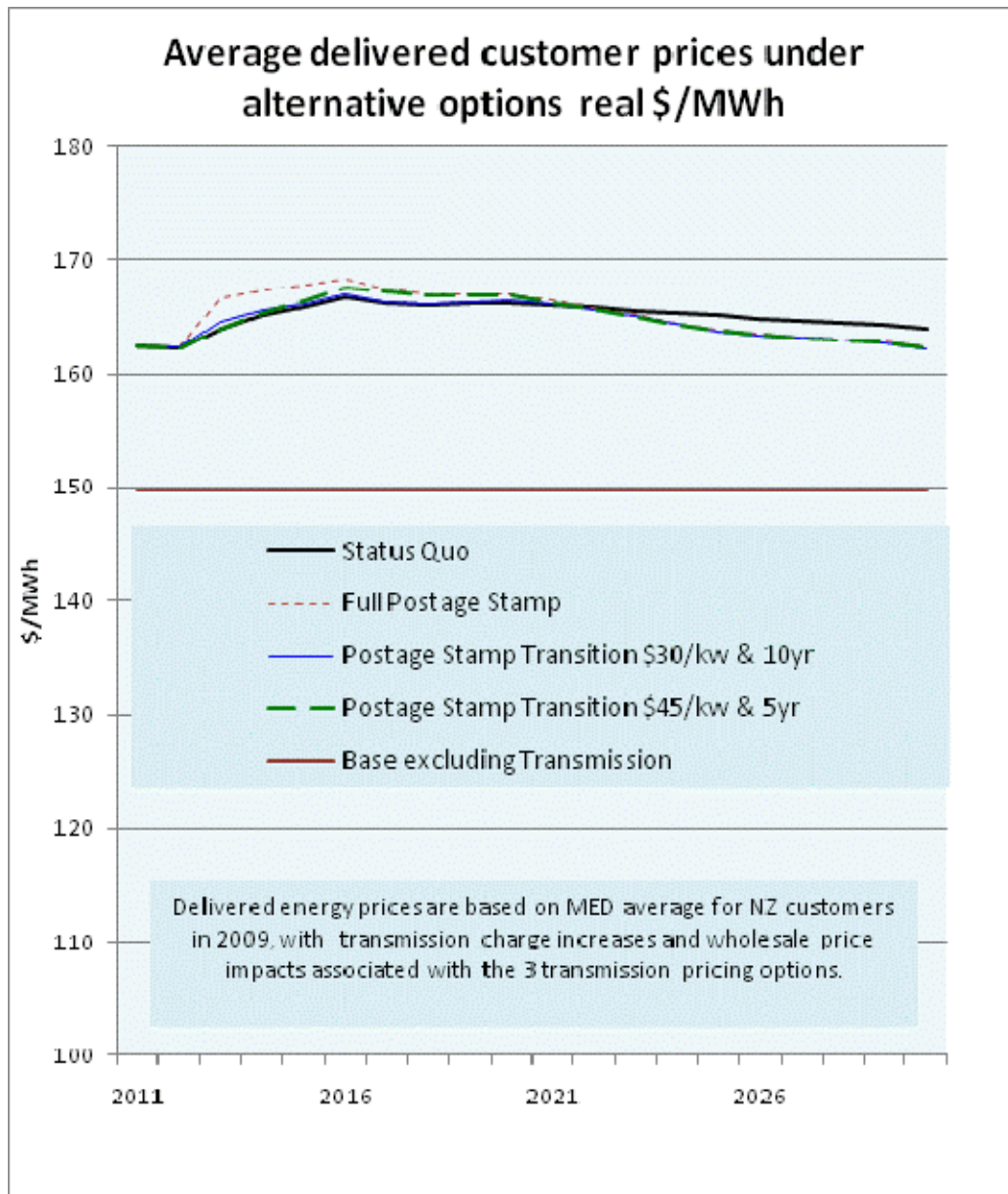


- 6.7.12 This chart shows there is high confidence that the net impact on delivered customer prices would be less than around \$1-2/MWh in the period to 2022, and there is a possibility for a \$3-4/MWh reduction beyond 2023.
- 6.7.13 These potential price impacts are small relative to overall charges. For example \$1/MWh is 0.6% of the NZ average delivered electricity price to customers in 2009<sup>79</sup>, 0.4% of residential prices and 0.9% of industrial prices. Figure 4 below illustrates the expected impact of these HVDC options on the average delivered electricity prices in NZ (excl GST). This chart includes the expected impact of new AC investments on transmission charges to loads and the expected impact of the HVDC postage stamp transition option<sup>80</sup>.
- 6.7.14 If the uncertainty regarding future wholesale price falls was considered to be a significant issue then it would be possible to choose a longer transition (e.g. \$30/kW and 15yrs, or \$45/kW and 10yrs) which provided a net value gain to customers to compensate for the extra uncertainty.

<sup>79</sup> Source MED Data file.

<sup>80</sup> Note that the chart uses 2009 average delivered energy prices as a reference and accounts for the impact on expected transmission charges and on wholesale prices of the HVDC options. The chart does not include any estimate of the future level of wholesale prices and distribution charges as this is simply set at the 2009 level.

Figure 4 Total Delivered end-use prices under status quo, full postage stamp and postage stamp transition



### Majority view on the appropriate postage stamp transition option.

6.7.15 The majority of TPAG members agreed any transition option must:

- avoid step changes in prices to end consumers with the costs recovered from existing grid-connected SI generators during the transition period based on the costs of existing HVDC assets as a starting point. This is to be achieved through a declining 'incentive free' charge to existing grid-connected SI generating stations beginning at \$30/kW.
- incorporate a transition period to provide confidence that the efficiency benefits will flow into the wholesale market, without making the design of an 'incentive-free' transitional

charge to existing SI generators unworkable. This is achieved by the selection of a 10 year transition period.

**Q11.** If a transition to postage stamp option were recommended to the Authority and progressed further, do you agreed with the majority view that the \$30/kW initial charge to existing grid-connected SI generators and 10 year transition period is appropriate? If not, please give reasons. Are there other issues with the transition to postage stamp options that should be considered? Please provide details.



## **7 Assessing options for deeper or shallower connection**

### **7.1 Introduction**

7.1.1 This section:

- a) provides background to the consideration of a deeper or shallower connection definition or a deeper allocation of costs to specific participants;
- b) describes the interactions between aspects of the Commerce Commission's regulatory role and the development of possible deep connection options that lead the TPAG to conclude that progressing this work further requires close coordination with the Commerce Commission; and
- c) follows the analysis framework set out in section 4 to:
  - i) consider whether under the current definition of connection assets, there is a possible market or regulatory failure or opportunity for efficiency gain for the long term benefit of consumers sufficient to justify the consideration of other approaches;
  - ii) consider possible alternative options;
  - iii) assess the costs and benefits of the options by applying the efficiency considerations set out in section 4 and using the status quo as a counterfactual;
  - iv) compares the costs and benefits of the options but notes that coordination with the Commerce Commission would be required before any firm conclusions can be reached.

### **7.2 Background to the consideration of deeper or shallower connection**

7.2.1 TPAG's terms of reference require the TPAG to consider providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so.

7.2.2 The Stage 2 Consultation Paper identified a number of options (such as specific and general bespoke pricing, flow tracing and 'but-for' options) to provide additional signals to defer reliability-driven transmission investments. It also identified a number of issues with the current definition of deep connection assets.

7.2.3 In submissions:

- a) Todd Energy, Contact and Powerco agreed that there are opportunities to improve incentives to defer reliability-driven transmission investment.
- b) Transpower commented that there will only be a net benefit if the incentive leads to investment in peaking generation or DSM that is more cost effective than the transmission investment it is displacing. It doubted that a simple bespoke generator credit pricing mechanism could deal with issues related to investment timing and reliability necessary for local peaking generation to be an effective alternative to transmission.
- c) Meridian and Genesis commented that delays in investing in transmission should not occur if the result is reduced competition in the energy market.
- d) Three large users wanted more work on 'but-for' and saw similarities with flow tracing.
- e) Contact, EECA and Meridian wanted more work on flow tracing but Todd Energy, Northpower and Transpower did not support it (citing issues such as complexity, legality,

auditability, instability, threshold distortions, unclear benefits, inadequate handling of ‘stand-by’ assets and contractual issues).

7.2.4 The TPAG considered the options included in the stage 2 consultation paper and the submissions.

7.2.5 As set out in section 5, the TPAG decided to consider options for shallower or deeper connection or deeper allocation of costs to specific participants rather than ‘providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so’.

### 7.3 Interactions with Commerce Commission regulation

7.3.1 In progressing analysis of deeper connection or a deeper allocation of interconnection costs to specific customers, the TPAG has repeatedly considered the interactions with aspects of Commerce Commission regulation. This includes the transmission investment approval process, including the transmission alternatives regime and distribution pricing regulation.

7.3.2 For example, further development of one of the deeper connection options, known as ‘but-for’ would require guidelines as to how Transpower and the Commerce Commission would identify beneficiary shares when investments are approved.

7.3.3 More generally, the benefits of all deeper connection options depend to a large extent on how effective the investment approval process, including the transmission alternatives regime, is.

7.3.4 This is because the possible benefits of deeper connection, flow tracing, and ‘but-for’ mechanisms largely arise from the incentive for parties paying for assets to provide quality information to, and participate in, the investment planning process for any future investment in assets that are directly allocated to them. This engagement in the planning process should lead to more options being considered, alternatives to transmission investments receiving a stronger hearing, and trade-offs between investment costs and reliability benefits being more actively explored.

7.3.5 The extent to which the deeper connection options improve the investment planning process and in particular the consideration of transmission alternatives therefore depends to a large extent on how effective the planning process including the transmission alternatives regime is. (Where the regime is highly effective, investment in alternative approaches to deeper connection or a deeper allocation of costs may not be justified.)

7.3.6 The transmission alternatives regime is currently being reviewed by the Commerce Commission with input from Transpower and other stakeholders as part of the development of its Capital Expenditure Input Methodology<sup>81</sup>. If the application of the regime proves to be robust then generation and demand-side options would compete effectively with reliability-driven transmission investments and the benefits from deeper connection arrangements could be low.

7.3.7 Under the existing transmission alternatives regime, Transpower is required to consider transmission alternatives when seeking approval for a grid investment and if the transmission alternative is approved, its costs can be recovered in the same way as a transmission asset (via the TPM). The transmission alternatives regime enables Transpower to enter Grid Support Contracts (GSC) which provide payment for demand management and local generation to defer reliability-driven investments.

<sup>81</sup> The input methodology developed by the Commerce Commission which sets out how capital expenditure will be assessed and approved by it.

- 7.3.8 In the situation where the customer who is paying for a major investment is a distributor they should have an incentive to promote or to offer transmission alternatives to Transpower in order to delay or avoid the grid investment if the cost of the alternative (which it will have to pay for) is less than the cost of the grid investment that it would otherwise pay for.
- 7.3.9 It should be recognised that there are some issues associated with the transmission alternatives regime. For example:
- a) There can be disagreement over whether the assessment should rest simply on comparing the standalone reliability of the alternatives (either demand-side or generation) against the transmission investment, or rather the assessment should be a comparison of the incremental increase in grid capacity under the grid reliability standards (deterministic in the case of reliability-driven investments or probabilistic in the case of economically-driven investments) for the two options.
  - b) GSCs with peaking generation may interfere with the wholesale market because of the subsidy component received from the regulated sector;
  - c) Transpower may want to only enter into short-term GSCs to reserve transmission alternatives as a risk management tool (to mitigate delays in grid construction, higher demand growth or asset failure) rather than a primary means of delaying or avoiding new grid investments.
- 7.3.10 These issues are matters for the Commerce Commission to assess, but they could limit the extent to which Transpower or other parties are prepared to recommend alternatives to transmission investment.
- 7.3.11 In addition, if the offtake customer is a distributor the incentive to reduce transmission costs will depend on how the Commerce Commission treats different expenditures in its regulation of distribution prices. If transmission charges are effectively a 'pass-through' then there may be diluted incentives for distributors to promote transmission alternatives, particularly if any costs incurred in procuring alternatives were not also a pass-through. The Commerce Commission is looking at various ways to give distributors the incentive to reduce transmission costs.
- 7.3.12 This is only an issue if the party proposing a transmission alternative regime is a distributor. The transmission alternatives regime is open to all participants including generators and demand-side. (In contrast, a direct price signal such as the RCPD-based interconnection charge applies only to transmission customers.)
- 7.3.13 In conclusion, the TPAG considers that any further analysis of deeper connection options requires close coordination with the Commerce Commission. Accordingly, the TPAG does not make firm recommendations for changes to the TPM in this area rather it provides analysis on possible options which is intended to support the Authority if, and when, it progresses these issues.

**Q12.** Do you agree with the TPAG's conclusion that any further analysis of deeper connection options requires close coordination with the Commerce Commission?

**7.4 Issues with the status quo boundary between connection and interconnection assets – possible market or regulatory failure, potential for efficiency gains? (CAP 2)**

- 7.4.1 The TPAG's analysis focuses on the potential for efficiency gains and does not consider the question of regulatory failure or market failure in the context of connection arrangements.

- 7.4.2 Currently the TPM separates the grid into connection, interconnection and HVDC assets. The current definition of connection is considered deep as it includes assets beyond those at the point of connection. Some connection assets are shared between connected parties with the costs allocated between connected parties in proportion to the anytime maximum demands or injections. Rentals derived from specific connection assets are allocated back to customers who pay for those assets.
- 7.4.3 Connection costs are currently approximately \$122m per annum, or 20% of the total AC revenue requirement. It is estimated that around \$22m of the connection costs relate to connection assets, that would not be included if a shallower definition was applied.

#### **Potential efficiency gains from changes to the connection-interconnection boundary**

- 7.4.4 In the Stage 2 Consultation Paper, the Commission suggested there may be possible efficiency gains from providing incentives to participants to take action to defer or avoid transmission investments where there are benefits from doing so. Providing a deeper definition of connection or allocating a deeper portion of interconnection costs directly to participants is a way of providing these incentives.
- 7.4.5 A number of major reliability investments have already been approved and committed. Any potential value from deeper connection options can only therefore arise from new uncommitted reliability-driven investments. The Commission estimated a potential value of \$200-\$300m NPV from deferring uncommitted reliability driven assets.
- 7.4.6 This estimate draws on 2010 SOO estimates of DSM and peaking plant which have since been revised downwards. It also assumed that all DSM and peaking generation investment could be relocated to avoid future reliability investments, whereas a portion of this value is likely to be achieved through the existing RCPD allocation method.
- 7.4.7 The total NPV of uncommitted reliability investments in the period 2015 to 2040 which could be deferred by DSM and peaking plant is estimated to be around \$300m<sup>82</sup> (at an 8% pre tax real discount rate). This is based on assumed peak demand growth of around 150MW per year.
- 7.4.8 The updated SOO scenarios have a peak demand growth of around 130MW/yr and around 18% of this is met by DSM and around 13% by diesel peakers (the most flexible plant in terms of where it can locate)<sup>83</sup>.
- 7.4.9 It is likely that the existing RCPD-derived charges under the status quo would provide incentives for some of the DSM options and embedded peakers, but there is scope for grid connected diesel peakers (which are needed to meet energy demand) to be located in those regions which are requiring reliability-driven grid investments. Given that these peakers were going to be built anyway (i.e. wholesale electricity prices are sufficiently high to pay for them), the cost of locating them appropriately to avoid grid investments as well is likely to be relatively low.
- 7.4.10 If it is assumed that 50-75% of the DSM and 25-50% of the diesel peakers will be located in regions with growing net demand (possibly as a result of the RCPD allocation method) then there may be scope for savings of up to 10-20% of the total reliability investment cost as a result of the

<sup>82</sup> This is estimated from Figure 3 on page 36 in the Stage 2 Consultation Paper, which indicates an average of around \$300m for each 5 year block from 2020. The present value of this is around \$300m in 2011, because uncommitted expenditure between 2011 and 2020 is much lower.

<sup>83</sup> These could be either open cycle gas turbines or reciprocating diesels.

flow Tracing or but-For options. This implies a maximum potential NPV value of \$30-\$60m NPV, substantially lower than the Commission's earlier estimate of \$200-\$300m NPV.

- 7.4.11 Some or all of this potential gain of \$30m-\$60m might be available through the transmission alternatives regime as operated by Transpower under the status quo. It is also likely that the risks of high nodal prices may induce investors in peaker generation to preferentially locate in regions which are subject to occasional transmission constraints. An estimate of the portion, of this \$30m-\$60m gain from alternative deeper connection options *might* be in the range \$15 to \$40m, noting that implementation and operational costs have not been taken into account. The nature of the analysis set out above, means these benefits are high-level estimates only, and even these benefits may be available through an effective transmission alternatives regime.

**Q13.** The TPAG has made a broad estimate of the possible efficiency gains from deeper allocation of costs to specific participants of \$15 to \$40m NPV. What do you think is the likelihood that such efficiency gains might be possible? Please give reasons.

### Other potential issues

- 7.4.12 The following issues were raised in relation to the current definition of connection by submitters to the Stage 2 Consultation Paper:
- a) TrustPower raised concerns with respect to the how contestable the provision of connection assets is, as Transpower appears to require a lower configuration standard for connection assets owned by it.
  - b) Todd Energy considered it unreasonable for a generator to contribute connection assets shared between offtake and generation built to a higher reliability standard than required by the generator.
- 7.4.13 The TPAG notes these issues but they have not been addressed in the TPAG's work.

## 7.5 Options Considered

- 7.5.1 Drawing on earlier work of the Commission and the Authority, and its own analysis, the TPAG has identified alternatives to the status quo. These are summarised in Table 29. The primary rationale for the development of alternatives is to find a means of allocating transmission costs in a manner that:
- a) better incentivises participants to provide good quality information to Transpower's planning and the Commerce Commission investment approval processes and promote commercially-driven investment where possible;
  - b) provides incentives to defer reliability-driven investments when it is economic to do so; and
  - c) delivers a better method to deal with boundary issues between connection and interconnection.

Table 29 Options for deeper or shallower connection

Option	Description	Rationale for Change
<b>Status quo</b>	The TPM separates the grid into connection, interconnection and HVDC assets. The deep connection charging regime includes assets at connection points and assets 'required' by individual customers. The costs of connection assets are shared in proportion to peak demands. Rentals on connection assets are returned to customers who pay.  There is scope to negotiate mutually beneficial arrangements as the provision of connection assets is contestable.	
<b>Shallow connection</b>	This would revert to a shallow definition of connection assets.	Disincentivise parties lobbying Transpower to investigate interconnection options versus more economic connection options to avoid charges.
<b>Flow tracing</b>	Allocate shares of transmission assets to offtake according to a flow tracing with a cut-off threshold which dynamically defines the boundary between allocated and postage stamped interconnection assets. Customers would continue to receive rentals on assets they pay for as now.	To introduce an ongoing flow tracing for allocating the costs of assets deeper into the grid to reduce boundary issues and to improve participation and outcomes in grid investment decision making.
<b>'But-for'</b>	One-off identification of the beneficiaries of new deep connection assets when these are approved under the grid investment process. Beneficiaries only pay for capacity that they require. Customers would receive rentals for share of investments they pay for.	To extend the beneficiary pays approach to more new assets when they are required. This should improve participation and outcomes in grid investment decision making.

7.5.2 The options are described in more detail in the following sections, and evaluated by applying the assessment framework described in section 4.

### Shallow connection

7.5.3 A shallow definition of connection means that only assets installed at the point of connection are included and the costs for those assets are allocated to that connecting party and/or parties. In its stage 2 submission, Transpower suggested a move to a shallow definition would avoid the costs associated with boundary issues between connection and interconnection. Transpower incurs the costs of exploring uneconomic interconnection options versus more economic connection options requested by parties seeking to avoid connection charges. The shift to a shallow definition would affect 4% of HVAC revenue (\$22M).

### Flow tracing design

- 7.5.4 Flow tracing has been prototyped and tested to an extent by the Authority<sup>84</sup>. This has provided some confidence that the approach is workable and has allowed variations in the key design parameters and issues such as pricing stability to be explored.
- 7.5.5 Flow tracing would be applied to offtake only and it would be possible to exclude assets accounted for under commercial arrangements or non-interconnection parts of the TPM (e.g. connection, deep connection, new investment agreements, HVDC, or potentially ‘but-for’ agreements etc).
- 7.5.6 A key parameter in the flow tracing is the cut-off threshold. It has been proposed that this be based on an Asset Concentration Index (ACI) based on the Herfindahl-Hirschman Index, essentially measuring the number of transmission customers sharing the asset. An ACI of 10,000 denotes a dedicated asset and by varying the ACI threshold the percentage of AC assets that were allocated or postage stamped can be determined. The table below indicates the expected split of HVDC assets in 2015 under three alternative thresholds.

**Table 30 Percentage of HVDC costs allocated under the flow trace Option**

Option	Threshold	Connection & allocated costs	Postage stamped interconnection
Status quo		17%	83%
Shallow flow tracing	ACI >8000	37%	63%
Medium flow tracing	ACI >6000	58%	42%
Deep flow tracing	ACI >4000	80%	20%

- 7.5.7 The flow tracing calculations would require data from SPD and be assessed every trading period. This would enable the ACI cut-off and flow shares to be determined dynamically every half hour and/or averaged over a longer time frame such as a month or year. Transmission pricing is likely to be based on accumulated annual flow shares.
- 7.5.8 The ACI cut-off could be based on total customer shares for each asset, but it may be better to use a regional rather than company defined assessment to avoid giving distribution companies an incentive to restructure or to embed generation to influence the cut-off<sup>85</sup> (i.e. disincentivise gaming behaviour).
- 7.5.9 It may be possible to provide a transition to flow tracing by gradually reducing the ACI threshold over time. An alternative transition might be provided by only applying the approach to ‘new’ assets as they are built. Note that this would require an objective basis for determining what was a ‘new’ transmission asset compared with one that was refurbished or replaced.

<sup>84</sup> A paper, *Flow Tracing Analysis*, presented to the Transmission Pricing Technical Group is available at: <http://www.ea.govt.nz/document/12160/download/our-work/advisory-working-groups/tptg/7Dec10/>

<sup>85</sup> For example a large distribution company may be tempted to split into 2 separate, but related, distribution companies in order to reduce the measured ACI and hence the cut-off so as to avoid being allocated a greater share of interconnection assets.

**'But-for' design**

- 7.5.10 Minimal work has been completed on how the 'but-for' option would apply in New Zealand. In order for this option to operate in practice there would need to be guidelines for how Transpower and the Commerce Commission would identify beneficiary shares when investments are approved. For offtake it may be possible to use flow tracing as a mechanism to assist in this regard. An objective basis for determining which assets are 'new' (i.e. not required to service organic growth and solely attributable to a particular party's demand or generation) would also be required. In addition there may be an investment cost threshold below which the approach would not be applied.
- 7.5.11 It may be possible for the identified beneficiaries to enter long term contracts with Transpower (this would involve issues relating to term, performance promises etc). Alternatively the Commerce Commission might agree to approve fixed asset cost shares between parties or a methodology for allocating costs as part of the TPM.

**Q14.** Do you agree with the range of options for deeper or shallower connection, or for deeper allocation of interconnection costs, that have been identified? If not, why not?

**7.6 Assessment of the options against the efficiency considerations**

- 7.6.1 The section assesses the options using the efficiency considerations described in section 4 relative to the status quo.

**Efficiency consideration 1: Beneficiary pays**

- 7.6.2 The TPAG supports the application of the beneficiaries approach as discussed in section 4 and considers that there may be material benefits to the investment decision-making process where beneficiaries can be readily identified. The beneficiary-pays approach suggests that a deeper allocation of costs to specific beneficiaries is likely to produce benefits and both flow trace and 'but-for' would aim to allocate a greater proportion of costs to beneficiaries.
- 7.6.3 Table 31 assesses to what extent the alternatives apply the beneficiary pays approach relative to the status quo.

**Table 31 Application of efficiency consideration 1: beneficiary pays (connection options)**

Option	Application of the beneficiary pays approach, assessment relative to the status quo
Shallow connection	Allocates fewer assets directly to beneficiaries than the status quo.
Flow tracing	Allocates more assets - both new and existing - to users as a proxy for beneficiaries. The flow tracing approach applies a formulaic approach to assessing beneficiary shares which is likely to be less costly to operate than the 'but-for' once it is established, and potentially more objective. On the other hand flow tracing assumes that benefit is proportional to allocated flow shares, which may not be reasonable in all cases. The assumption may be more reasonable if the flow trace is only applied to loads and the threshold is not set too deep. There may be issues if costs of reliability-driven assets are allocated to direct customers and distribution loads with different requirements for security.



'But-for'	<p>Allocates more new assets to beneficiaries than the status quo. The 'but-for' approach links the identification of beneficiaries to the investment process and as such it allows for a gradual targeted phasing in of a beneficiary pays approach as and when it is likely to have the greatest benefits in respect to efficient grid investment decision-making.</p> <p>However it does require a case by case assessment of beneficiaries which involves the practical issues and transactions costs involved in identifying beneficiary shares of new investments and boundary issues on each major investment. This will involve forecasts of load and other factors and the scope for lobbying and disputes will inevitably increase if the boundary is pushed deeper into the interconnected grid. It would also require an objective basis for distinguishing between 'new' assets and other capital expenditure (e.g. replacement or refurbishment)<sup>86</sup>.</p>
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### Efficiency Consideration 2: Locational signalling

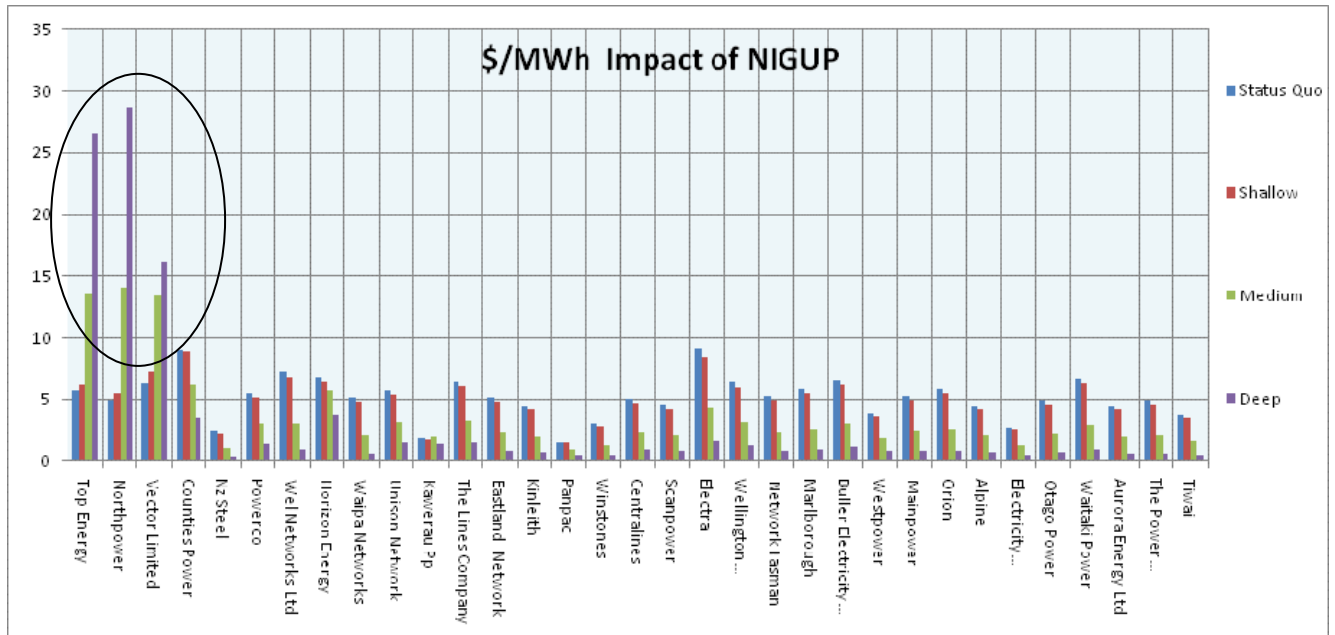
- 7.6.4 How strongly a methodology signals the cost of locational decisions depends to some extent on the depth that asset costs are directly allocated to customers.
- 7.6.5 A primary objective of both the flow tracing and 'but-for' options is to provide stronger incentives for loads to seek out cheaper options for additional load control or flexible generation<sup>87</sup> to delay or avoid new grid investments that they would have to pay for. The locational signal in these cases is an ex-ante signal – participants are incentivised to seek cheaper alternatives as they will anticipate higher costs being allocated directly to them once the investments are committed.
- 7.6.6 The following Figure 5 illustrates the potential size of the additional location signal<sup>88</sup> that would have been provided had flow tracing been in place prior to the approved North Island Grid Upgrade Plan investments in the upper North Island grid (NIGUP).

<sup>86</sup> These practical issues are canvassed in Page 71 of Appendix 2 "Further analysis of Stage 1 options", Electricity Commission July 2010, available at: <http://www.ea.govt.nz/document/9993/download/our-work/consultations/transmission/tpr-stage2options/>

<sup>87</sup> The generation needs to be sufficiently flexible (can locate anywhere and fast start) and reliable to delay/avoid the grid investment, and can be either embedded or grid connected. Typically it is diesel generation.

<sup>88</sup> This chart is based on estimates by the Authority using the prototype flow trace model. It used historical demand data scaled up to 2015, and simulated the difference in transmission prices with and without the \$400kV line to Auckland and the North Auckland and Northland grid investment.

Figure 5 Impact of NIGUP on Customer Transmission Charges



- 7.6.7 Figure 5 shows that under a medium or deep flow tracing, Vector, North Power and Top Energy would have been faced with a \$14 to \$27/MWh increase in their transmission charges attributable to the NIGUP and NAAn (North Auckland and Northland) investments in the AC grid, compared with only \$5/MWh under the status quo or a shallower flow tracing option. The prospect of paying these charges would have provided strong incentives for these companies to provide good quality information to Transpower and the Commerce Commission when the investments were being approved and to delay or avoid the grid investments by encouraging cheaper transmission alternatives if possible.
- 7.6.8 Both the flow tracing and 'but-for' options provide very strong 'ex-ante' incentives to promote options which can delay or avoid new grid investments before they are committed, however once a lumpy grid investment has been approved and becomes part of the fixed cost-recovery it is relatively hard to avoid<sup>89</sup>. This means that the incentive to actively manage load is strongest prior to a large grid investment, but then is reduced. This is sensible from an economic perspective if large investments result in a short term surplus of grid capacity.
- 7.6.9 On the other hand, the existing RCPD allocation method already provides an ongoing signal to manage load and to promote local embedded generation in regions where net demand is growing. In this case the incentive to control peaks is even greater following a new investment. This is reasonable where there is a series of small new grid investments required to meet growing demand but is not ideal where the investments are infrequent and large as the need for demand control is likely to be lower following a major investment. This issue might be addressed, under the status quo, by increasing the number of trading periods used to define the RCPD to 100 so as to blunt the incentive for load control while there is surplus capacity.

<sup>89</sup> The cost shares may be fixed under the 'but-for' approach, and under flow tracing are likely to be relatively insensitive to peak demand management. There may however be an unintended incentive to encourage local base-load generation to influence the threshold and hence the flow trace allocations in some situations.

- 7.6.10 Both the flow tracing and ‘but-for’ options will reduce the level of postage stamped interconnection costs, and hence the level of the RCPD-derived charge. Under the status quo the average real RCPD derived rate is expected to increase from around \$70/kW/yr to around \$90/kW/yr for the period 2015-2020. This provides a relatively strong incentive to control peaks in the upper North and upper South Islands. With a medium flow tracing option this would reduce to around \$45/kW/yr. The reduction would be less in the ‘but-for’ option as the allocation of shared costs would only be applied on new assets as they were built.
- 7.6.11 The TPAG notes that a deeper definition of connection assets, or a deeper allocation of costs, would provide enhanced locational price signals to electricity distributors and direct connect customers, thereby providing stronger incentives to engage in the investment approval process for reliability-driven investments. Although this should help promote the consideration of transmission alternatives, the TPAG also notes that the parties most likely to offer transmission alternatives would not receive this price signal directly.
- 7.6.12 As set out in 7.4, the possible benefits from the signals provided by ‘but-for’ or flow trace arise from deferring non-yet committed reliability investments. The TPAG has estimated these benefits at \$15m to \$40m NPV, but noted that the nature of the analysis means the estimate is high-level only and even these benefits may be available through an effective Transmission Alternatives regime.
- 7.6.13 The locational signals provided by the options are summarised in the table below.

**Table 32 Application of efficiency consideration 2: locational signalling (connection options)**

Option	Assessment relative to the status quo
Shallow connection	Provides a weaker locational signal.
Flow tracing	Provides strong ex-ante signal, depending on the threshold ACI used. Could provide benefits of the order of \$15m to \$40m.
‘But-for’	Provides strong ex-ante signal for new investment. Could provide benefits of the order of \$15m to \$40m.

### Efficiency Consideration 3: Unintended efficiency impacts

- 7.6.14 As with any practical cost allocation methodology there is the risk of creating perverse incentives for customers to reconfigure their networks, or to enter into arrangements with generators or loads simply to alter their allocation of transmission costs.
- 7.6.15 There are some anecdotal examples of this occurring under the status quo (to adjust the boundary between deep connection and interconnection assets), but this does not appear to be a significant issue, and is unlikely to be an issue under the shallow connection option.
- 7.6.16 There is scope for some perverse incentives arising from the flow tracing and ‘but-for’ options. Possible unintended efficiency impacts are summarised in the Table 33.

**Table 33 Application of efficiency consideration 3: unintended efficiency impacts (connection options)**

Option	Assessment relative to the status quo
Shallow connection	Will reduce perverse incentives on customers to avoid deep connection costs.
Flow-Tracing	There may be incentives for distributors to restructure themselves to influence the ACI cut-off threshold, but this could be addressed by basing the ACI measure on regional groupings of Grid Exit Points rather than distribution company ownership. Even so some offtake customers may have incentives to spend resources to influence load or generator behaviour simply to reallocate cost shares.
'But-for'	There will be strong incentives to dispute the identification of new assets and beneficiaries simply to reduce assigned asset shares. This may delay necessary investments. This delay and the disputes will involve some economic cost.

#### Efficiency Consideration 4: Competitive Neutrality

- 7.6.17 All options are largely neutral with respect to impacts on competition in the wholesale electricity market but there is potential for distortion in all options. In this respect, the exact details of the transmission Alternatives and 'but-for' regimes become very important. The options have not been assessed separately under this efficiency consideration.

#### Efficiency Consideration 5: Implementation and operating costs

- 7.6.18 Implementation and operating costs have not been closely examined, but estimates are included in the Table 34.

**Table 34 Application of efficiency consideration 5: implementation and operating costs (connection options)**

Option	Assessment relative to the status quo
Shallow connection	Low or negligible implementation costs, and possible lower operating costs.
Flow tracing	Would require process and software development and testing. The TPAG estimates that the set up cost could be in the region of \$2-4m and the ongoing incremental costs could be up to \$1m per year, including administration, maintenance, audit, data management, processing, disputes etc. This is \$10-\$12m NPV.
'But-for'	The costs of the 'but-for' option relate to the process of identifying beneficiary shares when new assets are approved and the costs of administering the cost allocations subsequently. This could be of the order of several millions per annum depending on the number of new investments that it was applied to and the number of disputes that might arise. For this indicative analysis it is assumed to be \$5-15m NPV.

### Efficiency consideration 6: Good regulatory practice

7.6.19 As set out in section 4, good regulatory practice is made up of a number of components. The discussion in this section particularly considers possible wealth transfers and step changes in prices, consistency over the grid, and durability aspects of good regulatory practice. Table 35 at the conclusion of the section addresses all the elements of good regulatory practice identified in section 4.

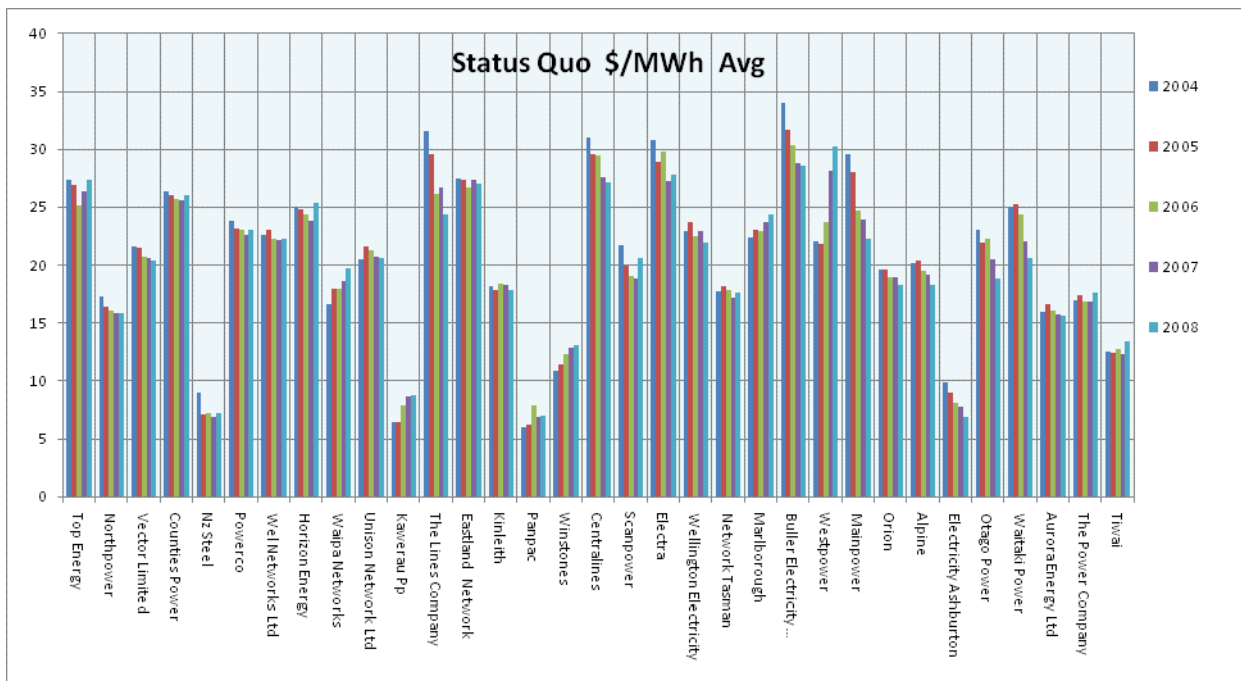
#### Wealth transfers and price step changes

7.6.20 In the TPAG's view any changes that result in wealth transfers must be justified by clear efficiency improvements. Given this it is relevant to explore the price impacts relative to the status quo.

7.6.21 Figure 6 shows the estimated average transmission charges in 2015 by customer under the status quo, based on scaled up demands from 2004 to 2008.

7.6.22 This is provided as a basis for comparing with the impact of implementing flow tracing. Note that under the status quo there is already a reasonable variation in average transmission charges between customers. This partly reflects different connection costs, but relates mainly to different effective load factors. The load factor is the average MW demand divided by the RCPD for each customer. Some customers are able to actively manage their contributions to the RCPD and hence achieve load factors greater than 100% (this appears to be the case for some of the major direct customers and some distributors with uncorrelated summer load patterns). Others have peakier and less controllable loads and hence have much lower load factors (most distributors). Note that there is also a degree of year to year variability in transmission charges, presumably mainly driven by fluctuations in load factor.

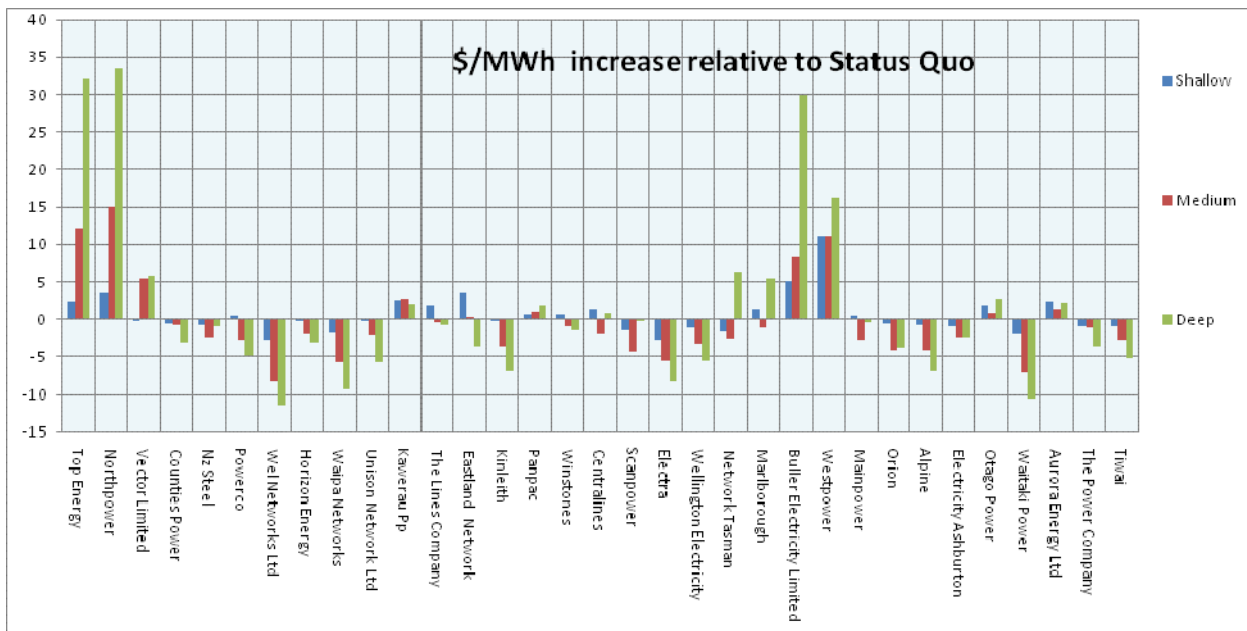
**Figure 6 Estimated average transmission charges under the status quo in 2015**



7.6.23 Figure 7 shows the impact on average transmission charges from a move to flow tracing. As can be seen the price and value impacts are potentially significant with a medium and deep flow

tracing methodology. Some customers would see an increase of over \$30/MWh with a deep flow trace, for example. The impact is less with a medium flow tracing option, but still involves price changes in the range of +\$15/MWh to minus \$10/MWh. Note that the impact is variable with customers in the upper NI and the West Coast of the SI being most adversely affected. There are also some significant winners. These are substantial wealth transfers and would require significant efficiency gains to justify. Note that a component of the value impact relates to the cost of the large NI grid investments which have been recently approved. These are committed and so the potential efficiency gains from improved investment decision-making in respect of these investments are no longer available.

**Figure 7 Estimated price impact of flow tracing in 2015.**



- 7.6.24 Using a shallow flow tracing option would avoid the price impact, but this is unlikely to provide significantly better incentives for improved grid investment decision-making.
- 7.6.25 It may be possible to provide for a transition (for example by increasing the depth of the flow tracing over time, or by applying it to 'new' assets as they are approved), but even in this case there would be significant value impacts once the transition period has ended as there is unlikely to be significant offsetting value gains.
- 7.6.26 The value impacts from the 'but-for' approach are likely to be eventually similar to flow tracing, depending on the rules for determining which new assets this applies to and the rules for identifying beneficiaries cost shares. The overall price impacts should be lower with 'but-for', since it applies to only new assets. However there will still be very significant price impacts for the individual customers involved in each new investment. Both options may also create local price impacts when individual assets need to be refurbished or replaced.

### Consistency over the grid

- 7.6.27 The flow tracing methodology has the advantage that it would apply consistently over the whole grid; old and new assets would be treated in a similar way.

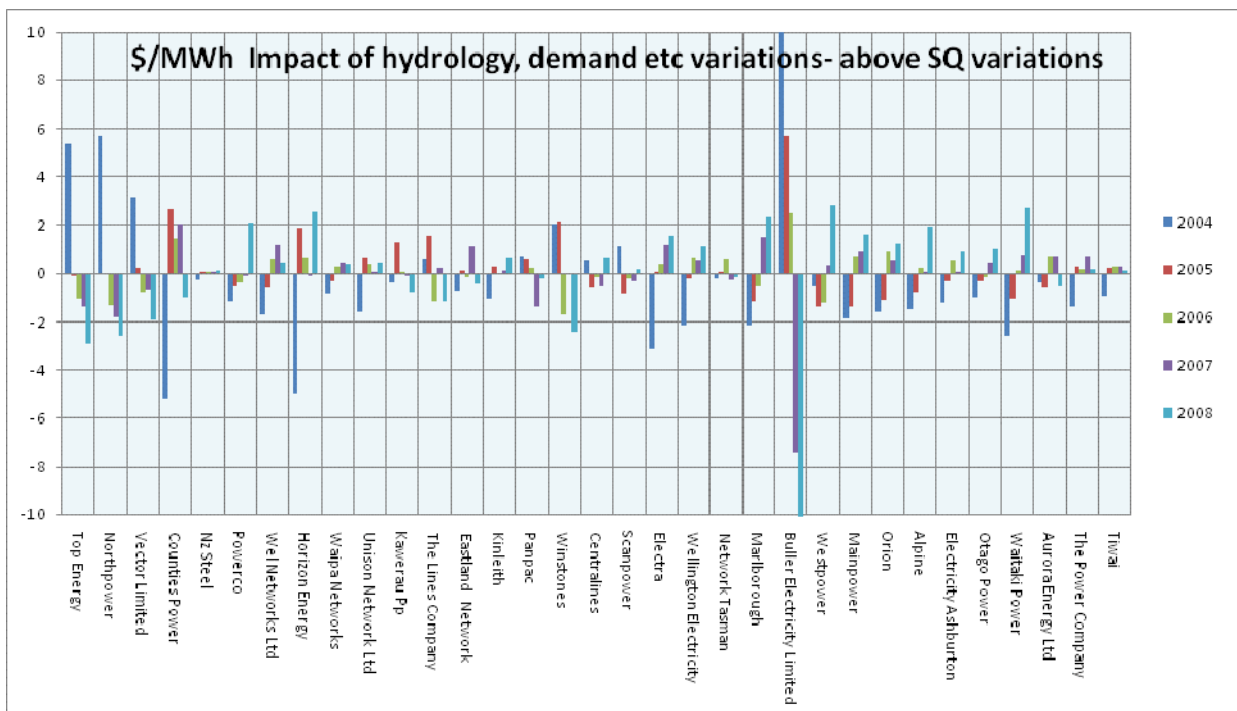
7.6.28 The ‘but-for’ option would be consistent in the sense that it was applied to all qualifying new grid investments, but it might result in some customers being treated differently simply because network assets in their region happened to be up for replacement or expansion. This may be efficient, but could be seen as arbitrary, and this could affect the acceptability and durability of the option and could result in costly disputes<sup>90</sup>. There may also be some scope for disputes over the definition and application of the cut-off in the flow tracing option.

### Durability

7.6.29 An earlier attempt to use load flow to allocate costs resulted in significant year to year price fluctuations. This has created a poor perception of flow analysis as an allocation method amongst some stakeholders. While the new approach is fundamentally different and fluctuations are not necessarily bad per se, they can affect the acceptability and durability of an option, particularly if the fluctuations do not appear to serve any real signalling purpose.

7.6.30 Figure 8 illustrates the price fluctuations that might arise in 2015 with the medium flow tracing methodology over a number of years with different hydrology and demand. As can be seen the price fluctuations are relatively high for a few customers but are within the range  $\pm$ \$2/MWh for most customers. This would probably be acceptable as it is comparable with the fluctuations under the status quo.

**Figure 8 Pricing volatility under the medium flow tracing option in 2015 with historical flow patterns**



7.6.31 The status quo and shallow connection options are relatively simple and have been shown to be workable. The flow tracing and ‘but-for’ options are substantially more complex.

<sup>90</sup> The definition of ‘new’ versus ‘old or replaced or refurbished’ assets could be an issue in this regard.

- 7.6.32 Although flow tracing may be relatively complex to setup, once developed it is formulaic and should be relatively straight forward to operate and apply over time. There are a few parameters that may be subject to dispute (such as the definition and application of the cut-off).
- 7.6.33 The ‘but-for’ option is likely to be complex and may involve a number of specific issues concerning its application that may be disputed. These include:
- interpretation and rules over which new assets it applies to;
  - interpretation of guidelines over how to assess beneficiary shares at the time of investment approval given that this will involve the definition of a counterfactual or baseline and a number of forecasts and assumptions;
  - issues that arise if circumstances change significantly (e.g. change in grid connections, new loads, new local generators, etc); and
  - issues relating to what happens when a ‘new’ asset needs to be replaced or refurbished.
- 7.6.34 Table 35 summarises the assessment of the options against efficiency consideration 6: good regulatory practice.

**Table 35 Application of efficiency consideration 6: good regulatory practice (connection options)**

Option	Assessment relative to the status quo
Shallow connection	<p><b>Consistency between regulators</b> – Similar to status quo.</p> <p><b>Durability</b> – Similar to status quo.</p> <p><b>Consistency over time</b> – Similar to status quo.</p> <p><b>Consistency over grid</b> – Similar to status quo.</p> <p><b>Wealth transfers</b> – There may be some small wealth transfers, as the approximately \$22 million deep connection costs are reallocated as interconnection costs.</p> <p><b>Price step changes</b> – Small price changes for some customers (see wealth transfer comment).</p> <p><b>Market fit</b> – the same as the status quo.</p>
Flow-Tracing	<p><b>Consistency between regulators</b> – Similar to status quo.</p> <p><b>Durability</b> – Could face durability problems if prices are unstable although this will depend on the threshold chosen and the periods of measurement.</p> <p><b>Consistency over time</b> – Flow tracing can be applied relatively consistently overtime, although there may be some special cases where there are price stability issues.</p> <p><b>Consistency over grid</b> – Flow tracing can be applied relatively consistently across the grid and may be slightly more consistent than the current approach.</p> <p><b>Wealth transfers</b> – This will depend on the threshold level, but there could be substantial wealth transfers for some customers.</p> <p><b>Price step changes</b> – There would be price step changes reflecting the wealth transfers above, with the largest step price increases to customers in the upper North Island and West Cost of the South Island.</p>



Option	Assessment relative to the status quo
	<b>Market fit</b> – Similar to status quo.
'But-for'	<p><b>Consistency between regulators</b> – Will require coordination with the Commerce Commission via the transmission investment approval process.</p> <p><b>Durability</b> – Is likely to be susceptible to disputes over identification of beneficiaries and beneficiary shares.</p> <p><b>Consistency over time</b> – Should be relatively stable over time, but there may be issues when existing assets need to be replaced or refurbished.</p> <p><b>Consistency over grid</b> – Old and new assets would be treated differently.</p> <p><b>Wealth transfers</b> – The wealth transfers for 'but-for' are likely to be eventually similar to flow tracing depending on the rules for determining which new assets the approach applies to and how beneficiary cost shares are determined.</p> <p><b>Price step changes</b> – The overall price impacts would be lower than for flow trace, since it only applies to new assets. There will still be very significant price impacts for individual customers involved in each new investment.</p> <p><b>Market fit</b> – Similar to status quo, although this may depend if participants charged for the costs of the new assets gain any decision rights over the assets.</p>

**Q15.** The TPAG has assessed the 'but-for', flow trace and shallow connection options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.

## 7.7 Assessment summary

7.7.1 This assessment summary follows TPAG's analysis framework as set out in section 4.

### Application of CAP 2 – clearly identified efficiency gain; regulatory or market failure?

7.7.2 The TPAG's analysis set out in section 7.4 identified an opportunity for efficiency gains from incentivising customers to defer reliability investments through allocating the costs to specific participants through either a 'but-for' or flow trace approach. The estimated benefits are of the order \$15m to \$40m NPV, but the estimate remains high-level and depends on the effectiveness or otherwise of the transmission alternative regime, the grid investment process and distribution pricing regulation.

7.7.3 The TPAG has not reached a firm conclusion on whether these potential benefits justify a change from the status quo because further analysis of the efficiency gains and assessment of alternative options requires close coordination with the Commerce Commission. It has not considered whether the status quo arrangements are a regulatory or market failure.

**Q16.** Do you think there is justification for the Authority to progress further analysis of connection options or a deeper allocation of costs to specific customers? If so, please give reasons.

### **Application of CAP 3 – assessment of options against efficiency considerations using the status quo as a counterfactual**

- 7.7.4 Although the TPAG has not reached a firm conclusion on the application of CAP 2, it has developed options and made an assessment of options against the efficiency considerations. The analysis is intended to support the Authority if, and when, it progresses these issues. These key findings are summarised here.

#### **Summary discussion**

- 7.7.5 The ‘but-for’ approach is potentially attractive in that it extends the beneficiary pays approach in a targeted manner to new reliability-driven grid investments where the benefits in terms of locational signalling are likely to be greatest. However it may be costly to apply (depending on scope), and could give rise to a number of potentially contentious ongoing issues concerning its application.
- 7.7.6 The estimated efficiency benefits from the ‘but-for’ option may not be certain enough to justify the significant wealth transfers and price impacts that would result. Evaluation of the likely effectiveness of the transmission alternatives regime, in cooperation with the Commerce Commission, would be necessary before conclusions are possible. Further, the ‘but-for’ approach relies on the identification of beneficiaries at an early stage in the approval process for reliability-driven transmission investments. This also requires cooperation with the Commerce Commission since it would likely involve requirements to be included in the CapexIM for Transpower investment proposals.
- 7.7.7 The flow tracing approach is attractive in that, once established, it may be simpler and less contentious to operate over time than the ‘but-for’ option. However participant benefits are not always proportional to flow shares, and the price impacts and wealth transfers would be even more widespread. These might be mitigated to an extent by providing some form of transition.
- 7.7.8 The estimated efficiency benefits from the flow tracing option may not be certain enough to justify the significant wealth transfers and price impacts that would result. Evaluation of the likely effectiveness of the transmission alternatives regime, in cooperation with the Commerce Commission, would be necessary before conclusions are possible.
- 7.7.9 More evidence of significant problems arising from the existing deep connection approach is required to justify a move to a shallow definition of connection assets. The costs and difficulties of identifying the beneficiaries of deep connection assets do not appear to be sufficient to outweigh the benefits of retaining this approach.
- 7.7.10 Table 36 compares the main connection pricing options relative to the status quo. Where possible quantified benefits and cost estimates are included. Positive values indicate an overall efficiency gain in total NPV terms. Where it is not possible to quantify the benefits, a tick represents an improvement relative to the status quo.
- 7.7.11 The flow tracing option is assumed to be of medium depth for this assessment, as a shallow approach is unlikely to deliver significant efficiency gains, and a deep approach has more significant price impacts and wealth transfers.

Table 36 Assessment of the connection options relative to the status quo (deep connection)

Efficiency consideration	Shallow connection	Flow tracing (Medium)	'But-for'
<b>2 Locational Pricing</b>	Negative?	\$15-\$40m	\$15-\$40m
<b>5 Implementation &amp; operating costs</b>	\$0m?	-\$12-10m?	-\$15-5m?
<b>Quantified benefit (NPV 30yr)</b>	<b>Negative?</b>	<b>+\$3 to \$30m</b>	<b>+\$0 to \$35m</b>
<b>1 Beneficiary pays</b>	x	✓ <sup>91</sup>	✓✓ <sup>92</sup>
<b>3 Unintended efficiency impacts</b> Game boundary, cut-off and cost allocation	✓	X <sup>93</sup>	X <sup>94</sup>
<b>6 Competitive neutrality</b>	same	same	same
<b>6 Good Regulatory Practice</b> 1. Consistency btw regulators 2. Durability 3. Consistency over time 4. Consistency over grid 5. Wealth transfers 6. Price impacts 7. Market Fit	same ✓ same same low low same	same X X <sup>95</sup> ✓ <sup>96</sup> ± \$10/MWh ± \$10/MWh <sup>97</sup> same	Needs coordination XX <sup>98</sup> X <sup>99</sup> X <sup>100</sup> ± \$5/MWh <sup>101</sup> ± \$5/MWh same

<sup>91</sup> Flow tracing applies to all assets but assumes that benefits are proportional to flows for loads which is not necessarily the case.

<sup>92</sup> 'But-for' only applies to 'new' assets but might use a more sophisticated assessment of benefits. A flow based assessment might be one element of this assessment.

<sup>93</sup> There would still be some incentives to influence demand or generation to alter cost shares with Flow tracing.

<sup>94</sup> There would be incentives to lobby to influence the allocation of beneficiary shares at time of approval. If fixed shares are not applied and a flow sharing methodology is approved then there will still be incentives to change behaviour to reallocate shares on an ongoing basis.

<sup>95</sup> Flow tracing appears to be reasonably stable year on year, although there could be special cases where it is not.

<sup>96</sup> Flow tracing can be applied relatively consistently across the grid, and may be slightly more consistent than current approach.

<sup>97</sup> It may be able to reduce the initial price impact by a transition application of flow tracing, either increasing depth over time, or only applying to "new" assets as they are built (like 'but-for').

<sup>98</sup> Scope for disputes is high, and there is a different application to old and new assets.

<sup>99</sup> May be stability issues when assets need to be replaced or refurbished.

<sup>100</sup> 'But for' would treat old and new assets differently.

<sup>101</sup> Only applies to customers benefiting from 'new' assets.

## 8 Assessing options for static reactive compensation

### 8.1 Introduction

8.1.1 This section:

- considers issues arising from the current arrangements for SRC, and possible regulatory improvements and efficiency gains that could be achieved in addressing them;
- considers alternative options; and
- assesses the relative costs and benefits of the options.

### 8.2 Issues with the current arrangements for static reactive compensation – Possible market or regulatory failure, potential for efficiency gains? (CAP 2)

8.2.1 The TPAG's analysis focused on whether the current SRC arrangements lead to a possible regulatory failure, and the potential for the regulatory failure to lead to inefficiencies. The possibility of market failure was not considered.

#### Background

8.2.2 SRC refers to sources of reactive power<sup>102</sup> that provide local voltage support and increase power transfer limits into regions that are subject to voltage instability. Both the Upper North Island (UNI) and Upper South Island (USI) are regions where the transmission capacity of Transpower's grid is capped by voltage stability limits.

8.2.3 Improving the power factor<sup>103</sup> of loads (by lowering their reactive power consumption), and/or providing additional SRC within networks at or near the load centres are both ways of increasing voltage stability limits<sup>104</sup> and decreasing network losses<sup>105</sup>.

8.2.4 Transpower has forecast the need for substantial levels of reactive power investment in the UNI and USI regions for the next 10 – 15 years<sup>106</sup>. A proportion of this investment is required to support the reactive power demands of transmission customers, while the balance is required to provide the reactive power needs of the grid itself. Although the investment in SRC assets is relatively small in comparison with the overall scale of current transmission investments, the

<sup>102</sup> Such as static capacitor banks connected to networks or within customer electrical installations. Reactive power is the component of power that continuously flows between reactive sources and sinks within the network but conveys no net flow of energy. It is thus an 'overhead' of real power transmission in an AC network.

<sup>103</sup> Power factor is a measure of the efficiency of the transmission of power in a network. The power factor is the ratio between the real power and apparent power flowing at a point in a network. The highest power factor is equal to 1.0 (or unity) and represents the state where there is only real (useful) power and no reactive power flowing past the measurement point. A power factor of 0.95 means that one unit of reactive power is flowing (and reducing the capacity for the transmission of real power) for every three units of real power (e.g. 33 MVar of reactive power and 100 MW of real power).

<sup>104</sup> Traditionally, power factor is used in thermally constrained systems to indicate the amount of real (or useful) power being consumed or supplied. A power factor improvement from 0.94 to 0.99 increases real power transfer by 5%. This is not true for voltage stability constrained regions where improvement in power factor can significantly increase power transfer (voltage stability) limits. For example, in the USI an increase from 0.99 (lagging) to unity can increase power transfer limits by up to 5%.

<sup>105</sup> As the network itself (i.e. the lines and transformers through which the power flows) consumes reactive power when operating at high load levels, the greater the distance over which reactive power must flow to compensate a region with net poor power factor loads, the greater are the losses involved in its transmission.

<sup>106</sup> Transpower, Annual Planning Report 2011.

benefits, in terms of extending existing transmission capacity and the consequent deferral of major transmission line upgrades, are large.

- 8.2.5 In some circumstances, SRC investment would be more efficient if the equipment was located within local distribution networks or in end-use customers' electrical installations, rather than within the transmission network<sup>107</sup>.
- 8.2.6 Status quo arrangements rely on the power factor standard in the Connection Code<sup>108</sup> to determine the allocation of costs for SRC investment. This mechanism relies on the parties to the bilateral transmission contract framework to make alternative arrangements (non-compliance agreements) where the requirements in the Connection Code are not able to be met for particular points of service. However, these arrangements have been controversial with offtake transmission customers and Transpower.
- 8.2.7 Offtake customers in the UNI and USI regions have argued that the 'unity power factor' requirement in the Connection Code, intended by the Commission as an investment cost allocator, puts them in automatic breach of the Connection Code, as it is not possible to achieve an exactly unity power factor in practice<sup>109</sup>. Note that the LSI and LNI regions are treated differently in respect of minimum power factor than the USI and UNI regions – in general, these regions are not constrained by voltage stability considerations and are therefore not considered as part of the issue being discussed in this section.
- 8.2.8 Transpower has argued that the mechanism within the Connection Code for dealing with the issues associated with power factor measurement accuracy and the inevitable breaches of the requirement that will arise is unworkable. A standoff situation has developed, whereby Transpower has, in some cases, entered into non-compliance agreements with some offtake transmission customers and for others not complying chosen, at least for the time being, not to pursue the matter.

### **Possible regulatory failure?**

- 8.2.9 The objective of any approach to charging for SRC is to incentivise efficient investment in SRC equipment by ensuring that offtake transmission customers pay a cost-reflective charge for the reactive component of power flowing into distribution networks or a directly connected customer's premises. This objective is consistent with the Authority's statutory objective.
- 8.2.10 The status quo arrangements are problematic for two reasons:
- a) the status quo, relying solely on the absolute unity power factor requirements of the Connection Code for the UNI and USI regions is not possible to comply with; and

<sup>107</sup> Previous analysis by the Commission indicated that if demand power factor correction is required to support transmission then it is more efficient, in terms of net benefits, to correct power factor on the distribution network rather than the transmission grid. This is because the lower cost of grid-connected capacitors is outweighed by the reduced losses in the distribution network when SRC equipment is located close to poor power factor loads.

<sup>108</sup> The Connection Code is incorporated into the Code by reference at Clause 12.26. The relevant section (4.4 Minimum power factor) requires from 1 April 2010 for power drawn off the grid, that the customer must maintain a power factor of not less than 1.0 (unity) at each relevant point of service during each relevant regional peak demand period in the Upper North Island Region and the Upper South Island Region.

<sup>109</sup> Maintaining exactly unity power factor at any point of service, as the Connection Code requires, is not within a DTC's practical ability to fine tune in operational timeframes.

b) enforcement arrangements through transmission agreements create practical difficulties and are convoluted.

8.2.11 The TPAG concludes that the combination of these two factors indicates a regulatory failure that, if not remedied, may lead to dynamic inefficiencies in the way that investments in SRC equipment are made. In TPAG's view this regulatory failure warrants analysis of alternative options.

**Q17.** Do you agree with the TPAG's overview of the background on SRC and the identification of the regulatory failure described in this section? If not, why not?

8.2.12 The next section reviews the options considered in the Stage 2 Consultation Paper and develops a further option for assessment. It builds on the work undertaken by the Commission and takes into consideration the submissions received<sup>110</sup>.

### 8.3 The options

8.3.1 This section:

- describes the options proposed in the Stage 2 Consultation Paper;
- reviews the stage 2 options and identifies an additional option, the 'amended kvar option'; and
- identifies two options for assessment relative to the status quo.

8.3.2 The Stage 2 Consultation Paper proposed that there may be benefits in alternative reactive power investment regimes. It proposed three possible alternatives to the status quo. These options are summarised in Table 37.

**Table 37 Reactive power stage 2 options**

Option	Description	Rationale for Change
<b>Status quo</b>	No change to current arrangements, whereby the Connection Code requires that grid off-take at points of service have unity power factor during periods of regional coincident peak demand.	
<b>1: Amended status quo</b>	Widen the acceptable power factor range by requiring that off-take customers maintain 'unity or leading power factor' <sup>111</sup> , during regional peak demand periods. Otherwise, as for the status quo option, retain the Connection Code enforcement mechanism.	A power factor range is practically achievable. It should remove the concerns in respect of the status quo requirement to maintain unity power factor. Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the transmission customer, who could choose between alternatives.

<sup>110</sup> See <http://www.ea.govt.nz/our-work/consultations/transmission/tpr-stage2options/>

<sup>111</sup> For demand, a leading power factor is where reactive power flows in the opposite direction to the real power flow. So if the power flow is into the distribution network, the reactive power flow would be back into the transmission grid. Flows of reactive power against the predominant direction of real power flow can, within certain bounds, be beneficial in terms of transmission stability.

Option	Description	Rationale for Change
<b>2: Connection asset definition</b>	<p>Include new regional SRC equipment within the definition of connection assets.</p> <p>Widen the status quo power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.</p>	<p>Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the offtake transmission customer, who could choose between alternatives. If a net reactive power demand persists during periods of regional peak demand, any grid-connected SRC equipment necessary to supply this demand is charged user-specifically to the offtake transmission customer causing the demand, via the connection charge.</p> <p>The Connection Code power factor requirement is widened to provide a fall back <i>de minimis</i>.</p>
<b>3: kvar charge</b>	<p>A new reactive power charge is implemented that charges offtake transmission customers for the reactive power taken off the grid by them during regional peak demand periods. The charge is set at a level that reflects the investment costs of providing new regional SRC equipment.</p> <p>Widen the status quo power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.</p>	<p>Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the offtake transmission customer, who could choose between alternatives. If a net reactive power demand occurs during periods of regional peak demand, a charge is levied for this.</p> <p>The Connection Code power factor requirement is widened to provide a fall back <i>de minimis</i>.</p>

8.3.3 The following sections elaborate on the options identified in the Table 37<sup>112</sup>.

### Status quo option

8.3.4 The status quo provisions for reactive power were developed by the Commission on the basis of the following rationale.

- a) The power factor requirements in the Connection Code are intended to form the basis of cost allocation – users taking reactive power off the grid at a point of service at times of peak regional demand are allocated responsibility for the costs of its provision in the UNI and USI regions.
- b) The Connection Code forms part of the transmission agreement between Transpower and its customers and enforcement of the provisions of the Connection Code are therefore a bilateral matter between Transpower and its customers.

<sup>112</sup> Further detail of how these options might work is provided in Appendix 5 of the stage 2 consultation paper. See <http://www.ea.govt.nz/document/9996/download/our-work/consultations/transmission/tpr-stage2options/>

- c) While the Connection Code is intended to set out the technical standards and requirements that Transpower and its customers must meet, it can be departed from where non-compliance agreements are negotiated. If a cost was involved in a specific case of departure (such as where agreement was reached that Transpower would make an investment in SRC equipment), the responsibility for that cost, while not prescribed in the Connection Code, can be negotiated and allocated to the party causing the departure from the Connection Code.

8.3.5 Thus offtake transmission customers would have choices in meeting their Connection Code obligations in respect of reactive power. The alternatives are not mutually exclusive (i.e. a combination may provide an optimal outcome) and would include:

- a) investing in SRC equipment themselves and locating it optimally within their distribution networks<sup>113</sup>;
- b) requiring or incentivising their end-use customers to invest in power factor correction equipment or in appliance choices that provide good power factor performance; and
- c) entering into a new investment agreement with Transpower, which would provide and operate large-scale SRC equipment (e.g. static capacitor banks) connected to the grid within the local region.

#### **Amended status quo option**

8.3.6 As noted earlier, transmission offtake customers have argued that the 'unity power factor' requirement in the Connection Code, puts them in automatic breach of the Connection Code, as it is not practically possible to achieve. Transpower has argued that it has no effective mechanism for ensuring compliance within the Connection Code when dealing with the inevitable breaches, and the potential for hold out, by transmission customers.

8.3.7 An amended status quo option would involve amending the minimum power factor standard in the Connection Code for the USI and UNI regions to 'unity or leading power factor' (rather than 'not less than unity power factor') and retaining this standard as a basis for determining the allocation of costs for any grid-based SRC investment.

8.3.8 Amending the Connection Code standard to unity or leading power factor has the benefit of removing some of the issues around non-compliance that were introduced by the status quo arrangements but retains that option's intended compliance mechanism involving the negotiation of non-compliance agreements.

#### **Connection asset definition option**

8.3.9 This would involve a transmission pricing-based solution that requires:

- a) widening the definition of 'connection asset' to include new SRC investments to the extent to which they deliver reactive power to offtake transmission customers in a region; and
- b) retaining but relaxing the power factor requirement in the Connection Code to 0.98 lagging, so as to provide a fall-back power factor provision.

8.3.10 The 'extent to which they deliver reactive power to customers in a region' is determined by:

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<sup>113</sup> Optimal location would provide addition benefits by possibly deferring the onset of constraints and/or minimising losses within their own distribution networks.



- a) calculating the average kvar taken by an offtake transmission customer in the regional peak demand period in the relevant region (either the UNI or USI region); and
- b) dividing the amount determined in a) by the total capacity of all SRC assets in the relevant region.

8.3.11 Thus, an annual charge would be calculated and invoiced once the point of service metering data from the annual regional peak demand period was available. It would apply once a new regional transmission SRC asset was built.

8.3.12 This arrangement seeks to include grid-connected SRC equipment, such as static capacitor banks, within the class of connection assets (previously these assets would be considered to be interconnection assets) charged to users. This would implement the beneficiary-pays approach and provide offtake transmission customers with an option to either:

- a) provide power factor correction measures within their own networks (and/or encourage/require their end-use customers to do so within the customers' electrical installations); or
- b) rely on Transpower to provide power factor correction through investment in grid-connected SRC equipment, for which they would incur a cost-reflective charge.

#### **kvar charge option**

8.3.13 This option is similar to the connection asset definition option in that it relies on a transmission pricing-based mechanism to establish an efficient investment price signal. It would involve determining an appropriate kvar charge for grid-supplied reactive power to incentivise more efficient investment in SRC equipment. It would be applied to new investments only.

8.3.14 The proposed charge under this option would require that, once a new investment in SRC equipment was made by Transpower, offtake transmission customers would forecast and nominate to Transpower their aggregate average kvar draw from the transmission grid during the forthcoming RCPD period.

8.3.15 Transpower would calculate a kvar rate based on the replacement cost of a suitable investment in SRC equipment, determined by consolidating all offtake transmission customer nominations within the relevant region. A penalty charge would be applied for usage over an offtake transmission customer's nominated quantity, set at a rate based on the (higher) cost of providing dynamic reactive compensation equipment.

8.3.16 Offtake customers would respond to the kvar price signal by paying for grid-supplied reactive power (as measured at the RCPD periods) and, at their option, seek to reduce the charge by investing where efficient in their own SRC equipment and/or encouraging their end-use customers to maintain high power factors.

#### **The TPAG review of options**

8.3.17 The TPAG has reviewed the options (excluding the status quo) following consideration of the Stage 1 and 2 Consultation Papers and submissions and has added a fourth option, the *amended kvar option*.

**Option 1 – amended status quo**

8.3.18 The TPAG considers that option 1, amended status quo, is appropriate for assessment against the Authority's statutory objective and the CAPs.

**Option 2 – connection asset definition**

8.3.19 In the case of option 2, connection asset definition, the TPAG considers there are issues with the option as defined, as follows:

- a) Defining regional SRC assets as 'connection assets' adds complexity by effectively creating two sub-classes of connection assets that differ in the ways they are charged for:
  - i) 'normal' connection assets, the costs of which are recovered through asset-specific \$/year charges invoiced monthly to offtake transmission customers; and
  - ii) 'static reactive support' connection assets, the costs of which are recovered through a new charge that is based on each in-region offtake transmission customer's aggregate kvar draw at its points of service, following establishment of the annual RCPD period.
- b) Linking a charge asset-specifically to identified SRC equipment (such as specific grid-connected static capacitor banks) would imply that new investments should be subject to new investment agreements, in the same way that other new investments in connection assets are made. This would involve a multi-party negotiation, potentially involving high transaction costs and hold-out by parties.

8.3.20 The TPAG also observes that this option is in effect a kvar charge, because dollar costs are being recovered per kvar demand measured in a defined assessment period.

8.3.21 The TPAG considers this option is equivalent to a kvar charge but has higher transaction costs and there is a potential hold out problem.

**Option 3 – kvar charge**

8.3.22 In the case of option 3, while the concept underlying a kvar charge appears sound, the TPAG has concerns with the workability of 'nominate and penalty' methodologies.

8.3.23 Submitters to the Stage 2 Consultation Paper were concerned about the difficulty of forecasting a suitable level of average kvar for the next RCPD assessment period and about the basis proposed for establishing a penalty rate, the purpose of which would be to encourage accurate nomination.

8.3.24 Forecasting accuracy impacts the charge paid and transfers additional cost to parties whose forecasts prove to be inaccurate. Offtake transmission customers whose networks contain relatively little controllable reactive power capacity (such as embedded generators and switched static capacitor banks) will face significant forecasting uncertainty, as end-consumer demand has a significant and variable impact on point of service reactive power demand.

8.3.25 For these reasons, the TPAG considers that while the concept of introducing a price signal through a kvar charge methodology appears sound, a better option is likely available that would provide the benefits of efficient price signalling without the drawbacks of the kvar charge option identified to this point.

**Option 4 – amended kvar charge**

- 8.3.26 In essence, a price signal should enable offtake transmission customers to make efficient choices between:
- investing in distribution SRC equipment themselves;
  - relying on Transpower to invest in grid SRC equipment; and
  - encouraging or requiring their end-use customers to likewise take steps to improve any poor power factor.
- 8.3.27 The principle that offtake transmission customers should face the costs incurred for their average aggregate kvar draw from the grid at times of RCPD provides an appropriate cost allocator.
- 8.3.28 Existing grid SRC assets that provide regional reactive power needs are currently incorporated within the interconnection asset base and their costs are recovered through the interconnection charge. Accordingly, the revenue raised by Transpower through a new kvar charge should displace revenue that would otherwise be recovered through the interconnection charge.
- 8.3.29 A methodology similar to the current interconnection charge could apply to the kvar charge and work as follows:
- Transpower determines the LRMC of grid-connected SRC equipment. This provides an efficient kvar charge rate and can be arrived at by dividing the estimated annual capital and operating costs of a new grid SRC asset (or group of assets) by the capacity it (they) would provide. Accordingly, the charge would not be linked to any specific existing grid SRC assets but would be reflective of Transpower's new investment and operating costs for grid SRC assets in general.
  - Transpower uses the kvar demand data from the RCPD periods from the immediately preceding September – August capacity measurement period. From this data, it assesses the average reactive power draw from the grid in kvar, for each offtake transmission customer in the UNI region and the USI region. If an offtake transmission customer's net reactive power flow during the assessment period is 'negative' (i.e. reactive power is injected into the grid), the assessed quantity is set at zero.
  - Transpower calculates the expected revenue to be recovered from the kvar charge for the coming year by multiplying the result in a) by the sum of the offtake transmission customer results in b).
  - The interconnection charge is calculated as it is now, except that the expected kvar charge revenue determined in c) is subtracted from the interconnection revenue before the interconnection rate is calculated. This ensures that Transpower's target revenue is the same as it would have been without the kvar charge.
- 8.3.30 Thus, the current year's kvar charge is set based on the immediately preceding year's kvar demand, using a similar approach to that used for the interconnection charge. The benefit for an offtake transmission customer from decreasing its reactive power draw from the grid during the RCPD period is gained in the following year, since the impact of reduced reactive power draw is reflected in the following year's kvar charge.

- 8.3.31 Distributors subject to the Commerce Commission's price path regulation should be able to benefit where they invest efficiently in transmission alternatives by retaining a portion of the benefit realised for the current regulatory period.
- 8.3.32 A kvar charge calculated based on the methodology outlined is illustrated in Table 38.

**Table 38 Amended kvar charge Illustrated (indicative only)**

	USI region	UNI region	Comment
<b>LRMC of grid SRC equipment = kvar charge rate (per annum)</b>	\$4 – 5 /kvar <sup>114</sup>	\$4 – 5 /kvar	c.f. 2011/12 interconnection rate @ \$76.14/kW
<b>RCPD total reactive power demand</b>	90 Mvar	285 Mvar	From 2010 RCPD data
<b>kvar charge revenue (per annum)</b>	\$0.36 – 0.45M	\$1.14 – 1.42M	
<b>Reduction in interconnection rate (due to revenue substitution to the kvar charge)</b>	\$0.26 – 0.32 /kW (= 0.34 – 0.42 %)		From 2011/12 TPM <sup>115</sup> : Interconnection rate = \$76.14 /kW Total RCPD = 5,872 MW

- 8.3.33 While the proposed incorporation of a prescribed minimum power factor may appear to be unnecessary where an efficient, uncapped charge is provided for grid-supplied reactive power, the TPAG considers there is a case to specify a minimum level as an additional backstop measure.
- 8.3.34 Power factors in the UNI and USI during RCPD periods are generally at very good levels currently<sup>116</sup> following a period of steady improvement in the USI region over the last decade, while the UNI has remained relatively flat. However, while this trend is unlikely to dramatically reverse in the short to medium term, the TPAG considers it prudent for offtake transmission customers to retain a focus on a minimum level of power factor. The options are:
- Retain a minimum power factor requirement in the Connection Code for the UNI and USI regions as a backstop to any price signalling approach.
  - Provide a penalty charge for reactive power demand in excess of the level required to maintain a target minimum power factor.
- 8.3.35 Option a) would appear to suffer from the enforceability issues discussed earlier in respect of the status quo option variants. Option b) could strongly signal a minimum power factor if such a charge were set at a sufficiently high rate.
- 8.3.36 The question of at what level the minimum power factor should be set also arises. While a minimum of 0.98 lagging was discussed in earlier consultation, there appears to be little rationale in support of such a minimum. Since the objective is to provide a backstop measure, a minimum level corresponding to the long-established benchmark of 0.95 lagging would seem to be the most appropriate. This would provide alignment across the whole grid.

<sup>114</sup> Based on indicative replacement costs for 220 kV and 110 kV static capacitor banks, provided by Transpower.

<sup>115</sup> Interconnection rate data from <http://www.transpower.co.nz/f4358,41345188/appendix-2-transmission-pricing-2011.pdf>

<sup>116</sup> For 2010 the USI power factor during the RCPD period was ~0.996 (c.f. 0.972 in 2000) and the UNI was ~0.991 (c.f. 0.991 in 2000).

- 8.3.37 Regarding the level at which the penalty rate should be set, it needs to be high enough to trigger investment in transmission alternatives. In a report prepared for the Electricity Networks Association and submitted in an earlier consultation round, SKM provided budgetary costs for a range of distribution static capacitor bank options. The most expensive distribution option cost around \$11 / kvar<sup>117</sup>. Thus, a penalty charge of around \$15 / kvar would appear to be suitable.
- 8.3.38 For these reasons, the TPAG proposes that a penalty rate of the order of \$15 / kvar should apply for reactive power offtake in excess of the level corresponding to a power factor of 0.95 lagging<sup>118</sup>. To be clear, the two rates would apply progressively: the kvar charge would apply for demand between 1.0 and 0.95 lagging power factor and the kvar penalty charge would cut in and apply only for any additional reactive power demand between 0.95 lagging and 0.

#### Options selected for assessment

- 8.3.39 The TPAG has concluded that the options that will be assessed against the status quo in the following section are:
- Option 1 – amended status quo; and
  - Option 4 – amended kvar charge

- Q18.** Do you agree with the selection of SRC options selected for assessment? If not, why not?
- Q19.** For option 4, the amended kvar charge, do you support the approach of retaining a minimum point of service power factor for the UNI and USI regions as a backstop measure? If so, do you support the recommended approach of providing a penalty rate for demand in excess of the minimum?

## 8.4 Assessment of options against efficiency considerations

- 8.4.1 This section assesses the amended status quo and amended kvar charge options relative to the status quo.

### Efficiency consideration 1: beneficiary pays

- 8.4.2 The TPAG supports the application of the beneficiary pays approach as discussed in section 4. There are benefits to the investment decision-making process where beneficiaries can be readily identified, noting that, as explained in section 4, it is not necessary to identify all beneficiaries. The costs passed to beneficiaries should not outweigh the benefit they receive and the costs incurred identifying the beneficiaries should be relative to the efficiency gains expected.
- 8.4.3 In general, the beneficiaries of grid-connected SRC equipment can be readily identified at points of service because the static reactive support service being provided is:

<sup>117</sup> SKM, *Review of EGR Connection Code*, 24 September 2010 – see <http://www.ea.govt.nz/document/11142/download/search/>. Appendix A – VAR/Capacitor Bank Costs

<sup>118</sup> At some connection points power factor may fall below 0.95 lagging but with little impact on investment due to generation embedded in the network. In these cases, there may be a case for an exemption from the penalty. This will be considered at a later stage.

- a) able to be clearly defined – it is the provision of an aggregate average quantity<sup>119</sup> of reactive power that flows into the point of service during the RCPD period and can be expressed as an average demand over the assessment period in kvar;
- b) measurable – revenue-grade metering equipment is located at every point of service that records both real and reactive power flows in each direction in each half hour trading period (so-called four-quadrant metering);
- c) provided on a bilateral basis; and
- d) able to be valued – it can be directly related to the LMRC of SRC assets.

8.4.4 However, while options can be developed that implement the beneficiary-pays approach, the question of investment materiality must be considered. It is important to explicitly identify the asset investments where there may be efficiency gains from a beneficiary-pays approach. The two investment categories are:

- a) major grid upgrades of transmission capacity into voltage constrained regions (such as the UNI and USI regions), typically involving the addition of new inter-regional transmission lines; and
- b) investments in regional SRC equipment, such as:
  - i) grid and distribution network connected static capacitor banks; and
  - ii) demand-side management options, such as in-premises power factor correction equipment or selection of high power-factor appliances.

8.4.5 The kvar charge option should not impact on the timing of major capacity investments in grid capacity, such as new transmission lines into regions that are becoming constrained. The key assumption underpinning this view is that Transpower will always develop and submit for approval main transmission investments in an optimal sequence and consider non-transmission alternatives, including demand side management.

8.4.6 Thus, if an offtake transmission customer maintained an aggregate poor power factor across its points of service within a region in regional peak demand periods, Transpower would seek to invest first in all available lower cost options before seeking to have a major transmission line investment approved. Lower cost options would normally include one or more stages of grid-connected SRC equipment within the constrained region (up to the point where all of these options were exhausted<sup>120</sup>).

8.4.7 In summary therefore, the price signalling mechanism in the kvar charge option impacts the dynamic efficiency of investments in regional SRC equipment.

#### **Conclusion on beneficiary pays**

8.4.8 The TPAG concludes that a beneficiary pays approach has merit in the case of SRC equipment investment since:

<sup>119</sup> Reflecting that reactive power can flow in either direction at any instance in time and that the assessment of service provision in this case will be in half hour periods.

<sup>120</sup> In practice, a maximum level of regional SRC compensation exists, such that no further voltage stability improvement is gained through the further addition of SRC equipment. At this point, other options that provide improvements to the dynamic stability of the network must be considered.

- the service being provided by Transpower can be defined and is measurable; and
- the beneficiaries can be readily identified.

- 8.4.9 Option 1 would implement a beneficiary pays approach if offtake transmission customers were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which would rely on the same mechanism.
- 8.4.10 Option 4 would implement a beneficiary pays approach based on point of service reactive power demands in the previous year and does not rely on offtake transmission customers concluding new investment agreements with Transpower with the attendant problems of high transaction costs and holdout. It is therefore assessed as being superior to the status quo option in this respect.

### **Efficiency consideration 2: location price signalling**

- 8.4.11 As noted in paragraph 4.3.10, location price signalling in the context of transmission pricing can incentivise efficient co-ordination of demand-side, generation and transmission investment and efficient trade-offs between the costs and benefits of reliability.
- 8.4.12 The spot market in New Zealand has been developed within a framework that considers only the flow of inter-nodal real power. Reactive power flows are not taken into account and thus no pricing signals are provided for it within the energy market.
- 8.4.13 In terms of the current TPM, existing regional SRC installations are classified as interconnection assets – accordingly, the costs are recovered on a non-locational basis.
- 8.4.14 The choice and location of alternative investments in regional SRC equipment (including demand-side alternatives) has a material bearing on both the costs and range of benefits provided. For example, the following hypothetical alternative investments could provide valid solutions to improve poor power factor within a region:
- a) Transpower builds a 50 Mvar static capacitor bank at a major regional transmission node.
  - b) A distributor within the region installs 0.75 Mvar pole-mounted capacitor banks at 50 locations and gains a power factor side-benefit from replacing several overhead 33 kV sub-transmission circuits with underground cables.
  - c) Large industrial customers install power factor correction capacitors in their premises and all customers select high power factor appliances (e.g. high power factor compact fluorescent lighting).
- 8.4.15 While each of these alternatives on its own, or a mix of combinations of parts of each alternative, could provide satisfactory voltage support across a network region, each investment will involve unique costs and benefits (i.e. the costs and benefits are location dependent). Some level of investment at each of the transmission, distribution and end-consumer levels is likely to provide an optimal level of efficiency by maximising transmission and distribution capacity while minimising electrical losses. Seeking to provide a location price signal for investment in SRC equipment is therefore likely to be beneficial (particularly if such a signal is also provided to end-consumers).

**Quantification of benefits**

- 8.4.16 The benefits accrue from reducing network losses and providing increased transfer capacity of existing networks and consequentially deferring future upgrades.

*Loss reduction benefits*

- 8.4.17 Estimates of distribution network loss reduction benefits have previously been made<sup>121</sup>. SKM estimates that improvements in power factor, in the case of their analysis to unity, could provide approximately \$10M in loss reduction savings. The TPAG has reviewed this work and concluded that there is potential for *up to* \$10M in capitalised savings in losses within the distribution networks in the upper island regions<sup>122</sup>.

*Thermal capacity increase benefits*

- 8.4.18 Given that existing point of service power factors are generally quite high in the upper island regions, the potential for achieving further thermal capacity increases within the regional distribution networks would appear to be limited. However, improving from 0.99 lagging to unity power factor gives a 1% capacity increase. Using the 'rule-of-thumb' of \$1M/MW<sup>123</sup> for network augmentation could give:
- a) For the UNI (approx. 2000 MW @ 0.99 power factor) a potential of up to 20MW (1%) increase in capacity (valued at a NPV of \$20m).
  - b) For the USI (approx. 1060 MW @ 0.995 power factor) a potential of up to a 5MW (0.5%) increase in capacity (valued at a NPV of \$5m).

- 8.4.19 Hence, there appears to be a potential capacity benefit of up to \$25m from introducing a location price signal.

*Overall benefits*

- 8.4.20 Given the above, overall benefits might fall within the range from \$10.5m NPV (if only 25% of the potential were realised) up to \$35m NPV.

**Conclusion on location price signalling**

- 8.4.21 The TPAG concludes that introducing an efficient location price signal for investment in regional SRC equipment is viable and likely to provide benefits against the status quo option.
- 8.4.22 Option 1 would provide a location price signal for alternative asset investments, but only if customers were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which relies on the same mechanism.
- 8.4.23 Option 4 would provide an efficient location price signal for alternative asset investments by introducing a kvar charge on average reactive power drawn from the grid during RCPD periods. The kvar charge would be set at the LRMC of a grid SRC asset investment. In addition, option 4

<sup>121</sup> SKM *ibid* – page 4.

<sup>122</sup> SKM's analysis used an electricity price of \$0.05/kWh and on that basis determined \$5m of distribution loss benefit. At a more realistic value of \$0.10/kWh for the electricity price embedded within current retail prices, TPAG has determined an approximate value of avoided distribution losses of approximately \$10m.

<sup>123</sup> Note that this rule of thumb estimate is applicable to transmission capacity. Distribution capacity would cost more than this, so the benefit estimate is conservative.



does not rely on customers concluding new investment agreements with Transpower. It is therefore assessed to be superior to the status quo option.

### **Efficiency consideration 3: unintended efficiency impacts**

- 8.4.24 As has been noted previously, option 1 is unlikely to deliver any materially different investment behaviour from offtake transmission customers compared with the status quo.
- 8.4.25 By establishing an efficient price signal, option 4 is likely to incentivise efficient investment in SRC equipment by offtake transmission customers. Customers would face an efficient investment signal through the kvar charge. Distributors could also choose to pass a similar signal on to their end-use customers through distribution pricing.
- 8.4.26 With the introduction of a kvar charge, some costs would be shifted from those that pay the interconnection charge to those that would be subject to the new kvar charge.
- 8.4.27 With a kvar charge in place, significant investments in SRC equipment downstream of the point of service would have the effect of:
- a) reducing the utilisation of existing grid SRC assets; and
  - b) deferring investment in future grid SRC assets.
- 8.4.28 The first effect could introduce unintended efficiency impacts under a kvar charge because any decreased year on year kvar charge revenue would be recovered from the interconnection charge and thereby shift costs between participants. At the limit, where all UNI and USI DTCs maintained average unity or leading power factor at their points of service, there would be no kvar charge revenue.
- 8.4.29 However, the kvar charge revenue levels indicated in Table 38 show that they are very small compared with the amount of interconnection charge revenue. In addition, in practical terms, existing grid SRC assets are unlikely to become stranded as a result of distributor and end-use customer investments in power factor improvements. The likely outcome is that they would simply defer future grid investments in SRC equipment.

### **Conclusion on unintended efficiency impacts**

- 8.4.30 The TPAG concludes that:
- option 1 would be no different to the status quo option in respect of unintended efficiency impacts; and
  - option 4 is unlikely on balance to provide significant unintended efficiency impacts compared with the status quo.

### **Efficiency consideration 4: competitive neutrality**

- 8.4.31 The parties interested in investments in SRC equipment are network owners and their customers (being energy retailers and end-use customers). Introducing an efficient price signal that would encourage efficient investment in SRC equipment would appear to raise no competition issues.

### **Conclusion on competitive neutrality**

- 8.4.32 The TPAG concludes that no competition issues are raised under either of the options considered.

**Efficiency consideration 5: implementation and operating costs**

- 8.4.33 Option 1 is essentially the same as the status quo, and would incur a small regulatory cost in providing the necessary Connection Code amendment. The process to be followed in making such a change is set out in the Code at clauses 12.18 – 12.25.
- 8.4.34 As outlined in paragraph 8.3.29, option 4 relies on a substantially similar pricing mechanism to the existing interconnection charge. Advice from Transpower indicates an implementation cost in the range \$0.4 – 0.6M. Ongoing costs should be a very small increment of the existing cost to provide transmission billing.
- 8.4.35 Offtake transmission customers may face higher capex costs per kvar than would Transpower if SRC equipment is installed within their distribution networks as a transmission alternative. They would presumably select this option only if the benefits more than offset the additional costs. The SKM report provides helpful budgetary costs for a variety of capacitor bank installation options<sup>124</sup> at 11 and 33 kV. An 11 kV pole-mounted, switched (SCADA-controlled) capacitor bank of 0.75 Mvar capacity would cost around \$6 / kvar annually (c.f. \$4 – \$5 / kvar for grid-located capacitor banks from Table 38).
- 8.4.36 Thus, an additional \$1 – 2 / kvar of additional cost should be attributed to option 4, which equates to \$0.4m – \$0.8m annually for 375 Mvar of capacity or \$4m - \$8m on a capitalised basis.
- 8.4.37 Offtake transmission customers would face minor incremental costs in processing kvar charge invoices and there would be a small regulatory cost involved in introducing the change into the Code.

**Conclusions on implementation and on-going costs**

- 8.4.38 The TPAG concludes that the implementation and on-going costs would be as follows:
- option 1 would be trivial; and
  - implementation of option 4 would be in the range \$0.4m – \$0.6m, based on advice received from Transpower. On-going operating costs would be relatively minor. Additional costs of \$0.4m – \$0.8m annually due to the slightly higher costs of distribution SRC equipment against those of grid SRCs.

**Efficiency consideration 6: good regulatory practice**

- 8.4.39 As was outlined in the background and problem definition discussion in this section, the review of reactive power arrangements was commenced in response to concerns expressed by electricity participants in relation to the minimum power factor requirements in the Connection Code that apply to the UNI and USI regions. Relying on the provisions in the Connection Code to allocate costs and initiate efficient investments in reactive support equipment is problematic because:
- a) it requires that offtake customers in the UNI and USI regions maintain a power factor level that is not practically possible to comply with; and
  - b) enforcement arrangements through transmission agreements create practical difficulties and are convoluted.

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<sup>124</sup> SKM *ibid* – Appendix A

- 8.4.40 The amended status quo option does not materially improve on the status quo. While the specific concern relating to the impracticability of arranging for exactly unity power factor at a point (or points) of service is somewhat mitigated by providing a range of power factors that would provide compliance, the broader concerns in respect of Transpower's inability to enforce compliance and the difficulties inherent in concluding multi-party new investment agreements, remain.
- 8.4.41 Accordingly, the TPAG considers that the amended status quo option does not resolve the regulatory failure identified in the problem definition.
- 8.4.42 The option of introducing a kvar charge is assessed in Table 39 against the good regulatory practice criteria that were introduced in paragraph 4.3.18.

**Table 39 Assessment against good regulatory practice**

Principle	Comment
Consistency between regulators	A kvar charge is compatible with the Commerce Commission's transmission alternatives provision within the price path regulation that applies to non-exempt distributors. This provides for distributors to retain some of the benefits where they efficiently invest in transmission alternatives.
Durability	Option 4 is expected to be durable because it is based on, and is conceptually similar to, options that have been consulted on previously and have received broad support, particular from those parties that would be most directly involved (being Transpower and offtake transmission customers).
Consistency over time	Introducing a kvar charge requires a change from the status quo. This option therefore introduces a regime inconsistency at the point of its introduction. However, once introduced, an LRMC-based kvar charge should provide an enhanced and stable environment for investment decision making in the provision of SRC equipment over time.
Consistency over whole grid	The kvar charge mechanism is proposed to apply only in the regions of the grid that are subject to voltage constraint, being the USI and UNI. The mechanism is thus consistent within those regions but is unnecessary for the foreseeable future within the voltage-unconstrained LSI and LNI regions. It is therefore inconsistent over the whole grid, and less consistent than was the case with the status quo option (because an additional mechanism would be introduced by option 4). See also the further comment at 8.5.4.
Wealth transfers and step changes in prices	An initial wealth transfer and price step could be expected in the transmission charges for offtake in the UNI and USI that have significant net reactive power draws from the grid in the RCPD period. Once certainty is provided that the charge is to be introduced, these parties will have an opportunity to evaluate and possibly undertake investments that would mitigate the price step change. Table 38 indicates that the kvar charge is relatively modest in the revenue it would collect when compared against the other transmission charge components and efficiency gains have been identified for the option.
Market fit	The proposed kvar charge is conceptually similar to and compatible with the existing interconnection charge.

## Conclusions on good regulatory practice

8.4.43 The TPAG concludes that:

- option 1 does not implement materially improved regulatory practice against the status quo option; and
- on balance, option 4 is consistent with good regulatory practice under the assessment criteria in this section. Where there are negative impacts, they are very small and more than balanced by the improvements the option would provide over the status quo.

**Q20.** The TPAG has assessed the amended status quo and the amended kvar charge options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.

## 8.5 Assessment against efficiency considerations

8.5.1 Table 40 compares the options assessed relative to the status quo. Where possible, quantified benefits and cost estimates are included. Positive values indicate an overall efficiency gain in total NPV terms. Where it is not possible to quantify the benefits, a tick represents an improvement relative to the status quo.

**Table 40 Assessment of the SRC options relative to the status quo option**

Efficiency consideration	Option 1: Amended status quo	Option 4: Amended kvar charge
<b>2. Location Pricing</b> (see para. 8.4.20)	\$0	\$10.5m to \$35m
<b>5. Implementation &amp; on-going costs</b> Billing system upgrade (8.4.34) Additional DTC capex (8.4.36)	\$0 \$0	-\$0.4m to \$0.6m -\$4m to \$8m
<b>Quantified benefit (NPV 30yr)</b>	<b>\$0</b>	<b>\$6.1m - \$26.4m</b>
<b>1. Beneficiary pays</b> (8.4.9)	same	✓
<b>3. Unintended price impacts</b> (8.4.30)	same	same
<b>4. Competitive neutrality</b> (8.4.32)	same	same
<b>6. Good Regulatory practice</b> (8.4.43) 1. Consistency btw regulators 2. Durability 3. Consistency over time 4. Consistency over grid 5. Wealth transfers 6. Price step changes 7. Market fit	all same	✓ ✓ X X X (very small) X (very small) ✓
<b>Qualitative Score</b>	<b>X</b>	✓

**Observations**

- 8.5.2 The amended kvar charge option has the highest net benefit against the status quo option.
- 8.5.3 Possible wealth transfers and price step changes associated with option 4 are expected to be small and manageable in the transition period. Option 4 is rated as a negative in terms of consistency over time because it is a change from the status quo. It should be consistent over time in the future, however.

**Q21.** Do you agree with the TPAG's summary of the costs and benefits of the options assessed and its observations? If not, why not?

**Further comment regarding consistency over the whole grid**

- 8.5.4 This section considers only the USI and UNI regions, which are relevant to the regulatory failure being considered. However, it is anecdotally understood (but only at a high level) that there may be other issues with the prescription of minimum power factor at points of service in the LSI and LNI regions, as required by the Connection Code.
- 8.5.5 Leaving the LSI and LSI regions with status quo minimum power factor requirements based on a mechanism that is demonstrably unenforceable raises a further question as to whether a regulatory failure also exists with respect to the prescribed minimum power factor (of 0.95 lagging) in those regions.
- 8.5.6 An alternative may be to consider application of the proposed modified kvar charge option across all regions. However, while there may be a case to consider whether a kvar charge approach, suitably modified, could be applied to the LSI and LNI, it is first necessary to understand whether (and, if appropriate, to what extent) a problem and/or a potential inefficiency exists. While this issue is not further considered in this paper, the following question seeks to elicit information from submitters.

**Q22.** Do you think it appropriate that minimum power factor requirements are retained in the Connection Code for points of service in the LSI and LNI regions, when a view has been taken that such arrangements are unenforceable in the UNI and USI regions and thereby amount to a regulatory failure?

**Q23.** In your experience are there any other issues that arise from the current prescription within the Connection Code of minimum power factor for points of service in the LSI or LNI regions? Please provide background relevant to any issues you identify.

**Q24.** If you have identified issues in the previous question, do you think an approach similar to the amended kvar charge option, possibly incorporating a penalty charge for reactive power demand in excess of a set minimum power factor, would provide a better approach to address the issues you have identified? Are there other options that should be considered?

**8.6 Assumptions supporting the case for moving to an amended kvar charge**

- 8.6.1 The amended kvar charge option requires that a small component of Transpower's revenue, currently recovered through the interconnection charge, is able to be reallocated for recovery through the new kvar charge. While this does not require that the interconnection charge remains in the TPM in its current form, it is most easily understood if the current interconnection charge (or one that is substantially similar to it) is retained.

8.6.2 The amended kvar charge option does not require that specific grid assets or new investments are identified.

## 8.7 Conclusion and possible changes to the Connection Code and TPM for static reactive compensation

8.7.1 The analysis in this section supports the introduction of a kvar charge, as developed as option 4, within the TPM.

8.7.2 Implementing a kvar charge would require the following Code amendments:

- a) Removing the minimum power factor requirement from the Connection Code (Schedule 8 of the Benchmark Agreement) for the UNI and USI regions only. This would require that the process set out in the Code at 12.18 – 12.25 is followed. It is proposed that clause 4.4 (minimum power factor) is amended as follows<sup>125</sup>:

### *4.4 Minimum power factor*

- (a) *If **electricity** is being drawn off the **grid**, the Customer must, in the case of demand at Points of Service in the Lower North Island Region and the Lower South Island Region, maintain a Power Factor of not less than 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period.*
- (b) *For the purposes of this clause:*
  - (1) *the regional peak demand periods and regions are as defined in Schedule F of the **transmission pricing methodology**; and*
  - (2) *the relevant regional peak demand period is the regional peak demand period for the region in which the Point of Service is located.*

- b) Amending Schedule 12.4 Transmission Pricing Methodology to add the new kvar charge (better termed a *reactive power offtake charge*) and a penalty charge.

8.7.3 The annual reactive power offtake charge would require specification of:

- a) The points of service it would apply to, being those in the UNI and USI regions.
- b) Its unit of measurement, being net average offtake reactive power per customer in kvar.
- c) The time period used for its assessment, being the regional coincident peak demand (RCPD) for a customer at a customer location.
- d) The methodology to be used in establishing the annual \$/kvar charge rate, based on assessing the replacement capital and operating costs of a grid capacitor bank (or a group of banks of different sizes and voltages).
- e) The methodology must be developed to establish the expected reactive power offtake revenue, this revenue to be offset against the interconnection revenue requirement.

8.7.4 The penalty charge would require specification of:

- a) The points of service it is to apply to, being those in the UNI and USI regions.

<sup>125</sup> The amendment has been drafted by: (a) removing outdated date-based conditionalities; (b) removing references to requirements in respect of the UNI and USI regions; and (c) removing the apparently superfluous initial sentence (which read: *The Customer must ensure that its Equipment does not unreasonably draw on the reactive power resources of the **grid** during each regional peak demand period.*)

- b) The methodology to establish the process of applying and level of the penalty charge to apply when the power factor is less than 0.95 lagging.
- c) The interconnection revenue requirement would then be reduced by the quantum of the penalty charge applied.

**Q25.** Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.

## 9 Conclusion and draft Guidelines

### 9.1 Introduction

9.1.1 Within the constraints of its Terms of Reference the TPAG has been charged with reviewing the TPM. The focus of the TPAG's work has been on assessing options for:

- the allocation of HVDC costs;
- a deeper or shallower connection or a deeper allocation of costs to specific participants; and
- static reactive compensation.

9.1.2 The TPAG has put together an assessment framework to guide its analysis. The assessment framework is grounded in the Authority's statutory objective as it is applied by the CAPs. The assessment framework enabled:

- analysis of whether there were efficiency gains to be made or regulatory or market failures to be addressed (CAP 2); and
- development of a consistent structure to assess the efficiency costs and benefits of different options where appropriate (CAP 3).

9.1.3 The TPAG's analysis is intended to support the Authority in its deliberations when it comes to address the following questions:

- a) Is there a potential change to the TPM which would result in a net improvement (efficiency gain) for the long term benefit of consumers?
- b) Have the correct options been identified?
- c) Have the costs and benefits of each option been correctly identified? What is the net benefit identified from each option and the level of confidence that this will be captured?
- d) Which option has the highest combined net benefit associated with the highest likelihood of capturing the benefit?

9.1.4 Following consultation on this Discussion Paper, the TPAG will reconsider its analysis and conclusions and draft recommendations for the Authority on a preferred option for the TPM. If the recommendations are for a new TPM and the Authority accepts the recommendations, the Authority will release an Issues Paper for consultation proposing draft Guidelines to Transpower for proposed revisions to the TPM.

### 9.2 The TPAG's conclusions in summary

9.2.1 The TPAG has reached a number of conclusions some of which if accepted would lead to the release of an Issues Paper and Draft Guidelines. The TPAG's decisions and indicative Draft Guidelines reflecting those decisions are set out below.



HVDC conclusions in summary
<p><b>Analysis of whether there were efficiency gains to be made or regulatory or market failures to be addressed (CAP 2)</b></p> <p>The TPAG focused on potential <u>efficiency gains</u>.</p> <p>The TPAG members agreed that there was sufficient evidence of possible efficiency gains to warrant analysis of alternative options, but did not agree that there was sufficient evidence to justify a change from the status quo.</p> <p><u>In the view of the minority</u>, there is no clear and material efficiency gain to justify a change.</p> <p><u>In the view of the majority</u>, there is a clear and material efficiency gain to justify a change.</p>
<p><b>Assessment of costs and benefits of alternatives (CAP 3)</b></p> <p><u>In the view of the majority</u>, the postage stamp transition option offers the greatest efficiency gains relative to the status quo, without the significant wealth transfers associated with the postage stamp option. The postage stamp transition option moves to postage stamping HVDC costs to offtake customers but involves a transition where existing grid-connected SI generating stations continue to pay a portion of the HVDC costs for a period until consumers would be expected to gain the benefits of reduced wholesale prices. This transition would involve an ‘incentive free’ charge to existing SI generating stations.</p>
<p><b>Implications for draft Guidelines and possible Code amendments</b></p> <p>The minority view would involve no changes to the Guidelines with respect to HVDC costs.</p> <p>The majority view would involve changes to the Guidelines with respect to HVDC costs. Resulting Code amendment through change to the TPM.</p>

Deeper or shallower connection conclusions in summary
<p><b>Analysis of whether there were efficiency gains to be made or regulatory or market failures to be addressed (CAP 2)</b></p> <p>The TPAG focused on potential <u>efficiency gains</u>.</p> <p>The TPAG was not able to reach a firm conclusion on whether there were potential efficiency gains from changing from the status quo because of the interactions between the analysis of the options and the Commerce Commission’s regulatory role. In the TPAG’s view, close coordination with the Commerce Commission is required to make further progress on analysis of the deeper connection definitions or deeper allocation of costs to specific parties.</p>
<p><b>Implications for draft Guidelines and possible Code amendments</b></p> <p>The TPAG is not in a position to make recommendations for any changes</p>

<b>Static reactive compensation conclusion in summary</b>
<p><b>Analysis of whether there were efficiency gains to be made or market or regulatory failures to be addressed (CAP 2)</b></p> <p>The TPAG focused on a regulatory failure concerning the power factor requirements in the Connection Code and the enforcement provisions in the transmission agreements.</p> <p>The TPAG concluded that there was a regulatory failure that if not remedied may lead to inefficiencies in SRC investment.</p>
<p><b>Assessment of costs and benefits of alternatives (CAP 3)</b></p> <p>The TPAG concluded that an amended kvar charge offers the greatest net benefits. This option would involve an additional component in the TPM, referred to as a reactive power offtake charge. The charge would be set at a level approximating the long run marginal cost of grid-connected static capacitor installations and offtake customers would assess investments in transmission alternatives against it. The minimum power factor of unity for UNI and USI should be removed from the Connection Code, but a penalty charge in those regions is recommended for reactive power at peak periods where the power factor is below 0.95 lagging.</p>
<p><b>Implications for draft Guidelines and possible Code amendments</b></p> <p>The recommendations would result in changes to the Guidelines to introduce the requirement for a reactive power offtake charge and a penalty charge for the UNI/USI regions. There would be a consequential amendment to the Connection Code to change the minimum power factor requirements. The detail of the amendment to the Connection Code is given in section 8.7.</p>

### 9.3 Indicative Draft Guidelines

- 9.3.1 Following its consideration of submissions on this Discussion Paper, the TPAG is required to make its recommendations to the Authority Board. If the TPAG's recommendation is for an alternative methodology and the recommendation is accepted by the Authority Board, the Authority will publish for consultation an Issues Paper including Draft Guidelines and the Process for the development of the TPM.
- 9.3.2 Indicative Draft Guidelines to accommodate the TPAG's conclusions are provided below. These are included to enable stakeholders to understand how the TPAG's conclusions might be implemented through the Guidelines, and to provide an early opportunity to comment, including on the appropriate level of prescription.
- 9.3.3 In the case of the HVDC, the wording reflects the majority conclusions. If the minority conclusions were adopted there would be no revisions to the Guidelines in respect of HVDC cost allocation. The indicative Draft Guidelines include consequential revisions reflecting changes to the regulatory environment.
- 9.3.4 For comparison, the current Guidelines can be found at <http://www.ea.govt.nz/our-work/advisory-working-groups/tpag/24Feb11/>.

## Indicative Draft Guidelines for Transpower Transmission Pricing Methodology

### Introduction

1. This document is “the Guidelines” required by clause 12.83 of the Electricity Industry Participation Code 2010 (Code), which Transpower must follow in developing the transmission pricing methodology (TPM).

### Overall guidance

2. Transpower is to provide an explanatory document updating “Pricing for Grid Connection Services”, at a similar level of detail, and suitable for Transpower’s customers to understand the basis on which it levies charges.
3. In proposing revisions to the existing TPM in response to the Guidelines, Transpower is to detail the linkage between its charges for specific assets, its overall expected revenue and allocation of this to specific grid connection points.

### Application

4. The TPM applies to the revenue required to meet all of Transpower’s costs in providing transmission assets coming within Transpower’s regulated asset base and those approved by the Commerce Commission in accordance with Part 4 of the Commerce Act 1986.
5. Transpower may be required to fund alternatives to transmission. The detail (process and pricing) of any such arrangement will be specified in the Capital Expenditure Input Methodology currently being prepared by the Commerce Commission in accordance with section 54S of the Commerce Act 1986.

### Connection charges

6. No changes to connection definitions are proposed at this time.

### Reactive power offtake and penalty charges

#### Reactive power offtake charge

7. A new reactive power offtake charge is to be developed with the following parameters:
  - a) It is to apply to points of service in the UNI and USI regions.
  - b) It is to be measured by taking the net average offtake reactive power per customer in kvar.
  - c) A methodology must be developed to establish the annual \$/kvar charge rate, based on assessing the replacement capital and operating costs of a grid capacitor bank (or a group of banks of different sizes and voltages).
  - d) The time period for assessment of the charge is to be the regional coincident peak demand (RCPD) for a customer at a customer location.
  - e) A methodology must be developed to establish the expected reactive power offtake revenue, this revenue to be offset against the interconnection revenue requirement.

#### Reactive power penalty charge

8. A new reactive power penalty charge is to be developed with the following parameters:
  - a) It is to apply to points of service in the UNI and USI regions.
  - b) A methodology must be developed to establish the level of the penalty charge to apply when the

power factor is less than 0.95 lagging.

- c) The interconnection revenue requirement would then be reduced by the quantum of the penalty charge applied.

**Interconnection charges**

9. Charges for existing and new interconnection assets are to be on a postage stamp basis to offtake customers as is the current arrangement.
10. Transpower is to review the existing basis on which it calculates the interconnection charge at a grid exit point. Specifically Transpower must review whether the allocation of interconnection charges for the UNI and USI regions being based on the average of the highest 12 coincident peak half-hourly demands in the relevant capacity measurement period remains the most appropriate approach given the Electricity Authority's statutory objective contained in section 15 of the Electricity Industry Act 2010 and proposed changes set out in these Guidelines.

**HVDC charges**

11. The costs of the HVDC link and any replacement of, or upgrade to it, are over time to be allocated on a postage stamp basis to offtake customers on a basis similar to current interconnection charges.
12. There is to be a transition from the current arrangements where HVDC link costs are charged to all existing Grid-connected South Island generating stations. This is to be managed through a declining 'incentive free' charge to existing Grid-connected South Island generating stations beginning at \$30/kW, and involving a transition period of 10 years.

**Prudent discounts**

13. No changes to the prudent discount regime are proposed at this time.

**Q26.** Bearing in mind the indicative Draft Guidelines are intended to reflect the TPAG conclusions set out in this Discussion Paper, do you have any alternative drafting suggestions?

## Appendix A List of questions

Q1.	Do you agree with the TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision? If not, please provide your reasons.	22
Q2.	Do you agree with the TPAG's assessment that the changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPMs to be reworked?	28
Q3.	Do you agree with the TPAG's assessment that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective?	28
Q4.	The TPAG efficiency considerations: Has the TPAG identified appropriate efficiency considerations to assess the costs and benefits of different options? If not what other efficiency considerations would be appropriate?	36
Q5.	Do you agree there was sufficient evidence of a clearly identified opportunity for an efficiency gain to warrant analysis of alternative options for the allocation of HVDC costs? In particular do you agree with the assumptions and analysis contained in section 6.2 and further elaborated in Appendix D? If you do not agree please set out your reasons for reaching an alternative conclusion.	46
Q6.	Do you agree with the range of HVDC options identified for assessment? If not, why not?	52
Q7.	The TPAG has assessed the HVDC options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with and/or could provide further information on? Please provide details.	70
Q8.	What is your position on the two views? Do you have further evidence to support either the majority or minority view?	73
Q9.	Do you agree with the summary of the comparison of alternative options and the majority conclusion that leads to the identification of the postage stamp transition option as the preferred option? If not, please give reasons why.	76
Q10.	The TPAG's analysis assesses postage stamping the HVDC costs to offtake customers. In Table 17, the impact on the analysis of different postage stamp variants was considered. Do you think there are other variants of the postage stamp options that should be explored further? Please give reasons.	76
Q11.	If a transition to postage stamp option were recommended to the Authority and progressed further, do you agree with the majority view that the \$30/kW initial charge to existing grid-connected SI generators and 10 year transition period is appropriate? If not, please give reasons. Are there other issues with the transition to postage stamp options that should be considered? Please provide details.	81
Q12.	Do you agree with the TPAG's conclusion that any further analysis of deeper connection options requires close coordination with the Commerce Commission?	84
Q13.	The TPAG has made a broad estimate of the possible efficiency gains from deeper allocation of costs to specific participants of \$15 to \$40m NPV. What do you think is the likelihood that such efficiency gains might be possible? Please give reasons.	86

Q14.	Do you agree with the range of options for deeper or shallower connection, or for deeper allocation of interconnection costs, that have been identified? If not, why not?	89
Q15.	The TPAG has assessed the 'but-for', flow trace and shallow connection options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.	98
Q16.	Do you think there is justification for the Authority to progress further analysis of connection options or a deeper allocation of costs to specific customers? If so, please give reasons.	98
Q17.	Do you agree with the TPAG's overview of the background on SRC and the identification of the regulatory failure described in this section? If not, why not?	103
Q18.	Do you agree with the selection of SRC options selected for assessment? If not, why not?	110
Q19.	For option 4, the amended kvar charge, do you support the approach of retaining a minimum point of service power factor for the UNI and USI regions as a backstop measure? If so, do you support the recommended approach of providing a penalty rate for demand in excess of the minimum?	110
Q20.	The TPAG has assessed the amended status quo and the amended kvar charge options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.	117
Q21.	Do you agree with the TPAG's summary of the costs and benefits of the options assessed and its observations? If not, why not?	118
Q22.	Do you think it appropriate that minimum power factor requirements are retained in the Connection Code for points of service in the LSI and LNI regions, when a view has been taken that such arrangements are unenforceable in the UNI and USI regions and thereby amount to a regulatory failure?	118
Q23.	In your experience are there any other issues that arise from the current prescription within the Connection Code of minimum power factor for points of service in the LSI or LNI regions? Please provide background relevant to any issues you identify.	118
Q24.	If you have identified issues in the previous question, do you think an approach similar to the amended kvar charge option, possibly incorporating a penalty charge for reactive power demand in excess of a set minimum power factor, would provide a better approach to address the issues you have identified? Are there other options that should be considered?	118
Q25.	Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.	120
Q26.	Bearing in mind the indicative Draft Guidelines are intended to reflect the TPAG conclusions set out in this Discussion Paper, do you have any alternative drafting suggestions?	125

## Appendix B Approach to consideration of submissions

B.1.1 Under its Terms of Reference the TPAG is required to review and comment on submissions received on the Stage 2 Consultation Paper. The tabular summary below sets out:

- a) the key issues raised in submissions that are relevant to the TPAG work programme and Terms of Reference; and
- b) for each key issue, a brief commentary on how and/or where in the TPAG work programme and papers it has been addressed.

B.1.2 The submissions on the Stage 2 Consultation Paper are available from the Authority website, and the Commission prepared a summary of these submissions, also available on the website<sup>126</sup>.

	Relevant key issue in submissions	Approach to its consideration in the TPAG work programme
	<b>Transmission Pricing Review process</b>	
1.	Integration of the Review with other initiatives and the relative priority of the Review	<ul style="list-style-type: none"> <li>The TPAG notes the integration and priority issues raised. It also notes that, subsequent to the stage 2 consultation and the Electricity Industry Act 2010, the Authority published a revised Review process and timetable, established the TPAG, and set the TPAG Terms of Reference including the key deliverables expected of it.</li> <li>The TPAG acknowledges there are links between aspects of its work and other Authority work streams, (for example locational hedging assumptions are included in the TPAG's counterfactual for assessing transmission pricing options), and has considered integration issues to the extent that they are relevant to its work programme and key deliverables.</li> </ul>
2.	Timeframe for stage 3	<ul style="list-style-type: none"> <li>Refer comment on Item 1.</li> </ul>
3.	Requests for further consultation	<ul style="list-style-type: none"> <li>The Authority's revised Review process has included consultation on the regulatory framework. This Discussion Paper provides an opportunity for further consultation on the transmission pricing options.</li> </ul>
	<b>Framework under the new Act</b>	
4.	Implications of new Authority objective on Review to date	<ul style="list-style-type: none"> <li>The TPAG has considered the implications of the regime change in section 3.4. It also prepared a paper on the impact of regulatory changes which is available at: <a href="http://www.ea.govt.nz/document/13322/download/our-work/advisory-working-groups/tpag/tpag-meeting-28-march-2011/">http://www.ea.govt.nz/document/13322/download/our-work/advisory-working-groups/tpag/tpag-meeting-28-march-2011/</a></li> </ul>
5.	Consultation to clarify objective and Authority's interpretation of it	<ul style="list-style-type: none"> <li>The TPAG notes that the Authority set out and consulted on its interpretation of its statutory objective.</li> <li>The TPAG has reflected the objective and interpretation in its analysis</li> </ul>

<sup>126</sup> <http://www.ea.govt.nz/our-work/consultations/transmission/tpr-stage2options/submissions/>

		framework for assessing transmission pricing options.
6.	Considering transmission pricing principles	<ul style="list-style-type: none"> <li>The TPAG notes that the Authority has reviewed the regulatory framework for transmission pricing and undertaken a Code amendment that removes the pricing principles from the Code.</li> </ul>
	<b>Stage 2 analysis</b>	
7.	Economic theory consideration	<ul style="list-style-type: none"> <li>The TPAG notes the views expressed.</li> </ul>
8.	Analysis of the benefits of signalling economically-driven investment	<ul style="list-style-type: none"> <li>The TPAG notes issues raised regarding the GEM modelling and analysis. It has prepared a paper on the issues raised in submissions and matters it has raised itself. The TPAG's views on this are in section 2.8.5 and Appendix C.</li> </ul>
9.	Analysis of the benefits of signalling reliability investments	<ul style="list-style-type: none"> <li>The TPAG has noted and considered submitters' views on this in section 7 of this paper on assessing options for deeper and shallower connection.</li> </ul>
	<b>Stage 2 options</b>	
10.	Commission decision not to pursue some high level options	<ul style="list-style-type: none"> <li>The TPAG has particularly considered the GEM analysis which led to the Commission's decision and submitters' views. See Comment in 8 above.</li> </ul>
11.	The 'but-for' option	<ul style="list-style-type: none"> <li>The TPAG has considered the 'but-for' option and submitters' views on this option as part of its consideration of deeper or shallow connection options.</li> </ul>
12.	The 'capacity rights' option	<ul style="list-style-type: none"> <li>The Authority has explored this option further as a result of submitter comment. The TPAG considered the Authority's work and has assessed capacity rights as part of its consideration of HVDC options.</li> </ul>
13.	Options to avoid or defer reliability transmission investments	<ul style="list-style-type: none"> <li>The TPAG has considered this in its work on deeper or shallower connection options. It also considered bespoke pricing options at a high-level and comments on its consideration in section 5 on the scope of the TPAG's work.</li> </ul>
14.	The 'bespoke pricing' and 'flow tracing' options	<ul style="list-style-type: none"> <li>The Authority's Transmission Pricing Technical Group (TPTG) progressed these options following stage 2 consultation and considered submitters' views. Its work was reviewed by the TPAG as part of the options assessment.</li> </ul>
15.	Transmission Alternatives	<ul style="list-style-type: none"> <li>The TPAG considered high-level issues relating to transmission alternatives in its consideration of deeper or shallower connection options but notes that the Commerce Commission is considering transmission alternatives as part of its development of an Input Methodology to replace the existing Grid Investment Test for transmission investment proposals.</li> </ul>
16.	HVDC options	<ul style="list-style-type: none"> <li>Recovery of HVDC costs is a key issue on the TPAG work programme.</li> <li>The TPAG considered key issues raised in submissions and its own issues as part of its work programme.</li> </ul>
	<b>Other issues</b>	



17.	Connection issues	<ul style="list-style-type: none"> <li>The TPAG considered connection issues as part of its work on assessing options for deeper or shallower connection</li> </ul>
18.	Static reactive power compensation	<ul style="list-style-type: none"> <li>A TPAG working group considered static reactive compensation, and its work is reported in section 8 of this paper.</li> </ul>
	<b>General issues raised by submitters</b>	
19.	General considerations to be made in assessing changes	<ul style="list-style-type: none"> <li>These are addressed within the scope of the TPAG's analysis framework, described in the Discussion Paper.</li> </ul>
20.	Distribution company forecasting	<ul style="list-style-type: none"> <li>The TPAG notes the issues around distribution company forecasting which were particularly relevant to the deeper or shallower connection options about which the TPAG has not made firm conclusions. Any further work requires close coordination with the Commerce Commission.</li> </ul>
21.	Treatment of sunk costs	<ul style="list-style-type: none"> <li>This issue arises in a number of context in the TPAG's analysis and is mentioned where relevant.</li> </ul>
22.	Competition benefits and options value of transmission investment	<ul style="list-style-type: none"> <li>The TPAG notes this issue.</li> </ul>

## Appendix C Validating the stage 2 conclusions on the benefits of location-based price signals for economic transmission investment

### C.1 Background

C.1.1 A central part of the Commission's stage 2 analysis was the assessment of the potential benefits in introducing further locational signalling to encourage co-optimisation of investment in generation, load and transmission. The analysis considered the potential benefits of further locational signalling from two perspectives:

- a) For signalling in respect of future economic transmission investments; and
- b) For signalling in respect of deferral of future reliability transmission investments.

C.1.2 The results of the analysis for (a) above suggest there is limited benefit in providing enhanced locational signals to generators to ensure co-optimisation of economic transmission investments and generation. From these results, the Commission formed a preliminary view that there may be little justification for imposing additional transaction costs on the industry in order to introduce further locational signalling through transmission pricing in respect of economic investments. The Stage 2 Consultation Paper presented (amongst other things) this view and sought industry feedback on it. Submissions received were largely supportive of this conclusion drawn from the analysis.

C.1.3 This conclusion, and the analysis that underlies it, is pivotal to the work of the TPAG and the direction of the Review. With this in mind, the TPAG has reviewed the Commission's analysis in this area and tested the assumptions underpinning the analysis and the conclusions drawn from it. On the basis of the TPAG's deliberations, the work undertaken by the Commission and the Authority and the largely supportive submissions from participants the TPAG has concluded that there is no justification in imposing additional transaction costs on the industry in order to introduce additional locational signals through transmission pricing for economic investments in transmission assets.

C.1.4 This appendix summarises the TPAG's basis for reaching this conclusion. It includes

- a) an outline of the stage 2 analysis of the potential benefits of further location-based price signals for economic transmission investment; and
- b) the TPAG's considerations.

### C.2 The stage 2 analysis of the potential benefits of further location-based price signals

C.2.1 The Commission considered the potential benefits for further locational in respect of future economic transmission investments<sup>127</sup> using its Generation Expansion Model (GEM).

C.2.2 GEM is a long term capacity expansion planning model used for analyses of the New Zealand electricity sector. It is usually formulated and solved as a mixed integer programming problem, a type of optimisation model. The model yields a solution which minimises total system costs while satisfying a range of technical, economic and policy constraints. It was constructed to support the development of grid planning assumptions and grid investment approvals but has been used to

<sup>127</sup> It is likely that the different tests for investment in economic and reliability investment will be removed in the Commerce Commission's new Capex Input Methodology but this does not affect the validity of the outcomes from GEM which only address economic investments.

support analysis of problems such as the impact of electric vehicle uptake and the impact of schemes to reduce peak demand.

- C.2.3 GEM was used to derive an upper bound estimate of the national benefit, measured as a reduction in system costs, which could be obtained from an enhanced locational price signal through transmission pricing for generators.
- C.2.4 To simplify the analysis, the focus was on modelling the trade-off between remote generation requiring transmission investment and generation located close to load requiring no or more limited transmission investment. Transmission investment in this context is concerned with realising the economic benefit of reduced generation costs and is accordingly categorised as economic investment. As a result GEM does not address the question of whether enhanced locational signals would support the avoidance or deferral of the costs of reliability investments.
- C.2.5 Appendix 3 to the Stage 2 Consultation Paper provides a description of GEM and more detail on the model is available at <https://gemmodel.pbworks.com>.
- C.2.6 The approach to the GEM analysis was as follows:
- a) GEM was first configured to yield a solution representing a regime where the least cost generation options were built regardless of the interconnection costs (including DC assets) necessitated by those generation investment decisions. In this solution, locational signals from transmission pricing for interconnection assets played no role in the choice of generation.
  - b) GEM was then configured to co-optimize interconnection and generation investment. This simulates having a pricing regime that results in co-optimised transmission and generation investment.
  - c) The results of the two GEM solutions were compared and the difference in total system costs was taken to be an upper bound estimate of the possible benefit of allowing generation developers to respond to transmission pricing locational price signals.
- C.2.7 The analysis was based on the scenarios used for the Commission's 2010 Statement of Opportunities (SOO).
- C.2.8 In summary, this GEM analysis therefore:
- considered only the possible benefits of locational signalling of interconnection costs in comparison to a regime where there is no locational signalling in the pricing of interconnection costs;
  - did not consider any particular locational signalling approach, nor did it consider the implementation or transaction costs associated with any approach. The purpose was to identify whether there may be benefits that might justify further consideration of locational signalling within the transmission pricing regime; and
  - did not consider the benefits or otherwise of existing locational signalling from the grid investment process, connection charging, the HVDC charge or from nodal pricing as the effects of these would have been the same in both of the two GEM solutions noted above. The connection charges are modelled in GEM as being a component of the capital expenditure associated with generation investment.

- C.2.9 The results showed the benefits of allowing generation developers to respond to transmission pricing locational price signals to be positive (between zero and \$30 million) but smaller than the margin of error within the experiments.
- C.3 The TPAG's considerations**
- C.3.1 The TPAG has reviewed the analysis undertaken in stage 1 and stage 2 of the Review and has spent some time understanding GEM, understanding whether its use and the approach to the analysis is appropriate, testing the assumptions underpinning the analysis, and understanding the factors driving the results of the analysis.
- C.3.2 Submissions<sup>128</sup> on the Stage 2 Consultation Paper outlining the GEM analysis and its conclusions were largely supportive of the Commission's approach, although there were some concerns from submitters.
- C.3.3 Norske Skog agreed with the conclusion that there was limited justification in augmenting existing locational signals for economic investments but not on the basis of the GEM results. Norsk Skog was concerned that GEM contained too many assumptions to be a valid input into decision making. Its view was that the costs of generation investment and operation were of orders of magnitude greater than transmission investment and that transmission charges would have little bearing on generation investment decisions. In their view the use of GEM "was unnecessary to reach this common sense conclusion".
- C.3.4 The TPAG considered whether GEM was an appropriate tool to test whether locational signals through transmission pricing might be beneficial and whether there had been sufficient validation of the model. The TPAG considers that GEM suggests sensible building patterns that are to a significant extent being played out in reality.
- C.3.5 A number of the TPAG members were familiar with the work of the CEO Forum. The CEO Forum had also concluded there was little value in pursuing locational signals although it took a different analytical approach to that of the Commission. The coalescing of the conclusions provides further verification and comfort that the GEM approach is valid.
- C.3.6 In response to submissions the Commission and subsequently the Authority has undertaken additional analysis using the GEM model but with amended assumptions. These further reruns of GEM have altered results slightly but not materially enough to alter the conclusion that there is limited benefit in augmenting existing locational signals for economic investments. For instance, depending on the particular rerun being considered, total system costs may differ by as much as \$500 million (out of around \$20 billion) in NPV over a 31 year planning horizon, but the benefit of enhanced locational signals for economic transmission investments remains in the zero to \$30 million range.
- C.3.7 The key assumption that has been revised in GEM, since the Stage 2 Consultation Paper was prepared, relates to the peak capacity constraints. These constraints ensure that GEM builds sufficient capacity to meet peak winter demand when there is little wind availability and in the presence of certain other contingencies, e.g. HVDC or plant outages. Upon reflection, the Authority has determined that the constraints as configured for the 2010 SOO and the analysis reported in stage 2 were harsher than required. They have since been revised to operate more

<sup>128</sup> See submissions from Contact, EECA, Meridian, Mighty River Power, Trustpower, Vector, Powerco and Transpower.  
<http://www.ea.govt.nz/document/12634/download/our-work/consultations/transmission/tpr-stage2options/submissions/>

along the lines of the winter capacity margin. As noted above, this change causes total system costs to be reduced by a substantial amount over the entire modelled horizon. The benefit of enhanced locational signals for economic transmission investments is calculated to be \$13.5 million in net present value terms – practically the same as that reported in the stage 2 analysis.

- C.3.8 The TPAG considered the factors driving the analysis results. The TPAG members noted that the value of transmission build is low compared to generation build, and that some technologies are highly location-specific and that these factors have a significant bearing on decision making. For example, hydro and geothermal resources cannot be relocated, and of the factors influencing a decision to invest in such generation, transmission pricing will not be a primary factor.
- C.3.9 In summary, the TPAG concluded that:
- a) while there may be limited value in augmenting existing locational signals (nodal pricing, HVDC charge, deep connection and the relevant grid investment test) it is not confident that the benefits of making such a change outweigh the transaction costs of implementing the change;
  - b) the marginal benefits of such a change, as presently suggested by the GEM analysis make it difficult to justify the development of enhanced locational signals because of the associated costs;
  - c) implementing locational signals could be expected to be costly, complex and time consuming;
  - d) as with any such change it is also likely to result in unintended consequences which may be expensive to fix;
  - e) most of the potential pricing methodologies that have been considered (such as ‘tilted postage stamp’, augmented nodal pricing, load flow based approaches, etc) involve risks of unintended economic inefficiencies and are unlikely to be fully effective in optimally coordinating transmission and generation.
- C.3.10 In summary, the TPAG concluded that there is no justification in imposing additional transaction costs on the industry in order to introduce additional locational signals through transmission pricing for economic investments in transmission assets. In forming this conclusion it drew on its own discussions, the work undertaken by the Commission and the Authority, its understanding of the GEM analysis, and the largely supportive submissions from participants.

## Appendix D Analysis supporting the assessment of HVDC cost allocation options

### D.1 Introduction

D.1.1 This appendix sets out the TPAG's analysis on:

- the potential generation investment inefficiency caused by the HVDC cost recovery potentially delaying cheaper SI options relative to North Island options of the next 30 years;
- the potential value impact to end use customers from a shift of HVDC cost recovery from SI generators to customers; and
- the potential peaking generation investment inefficiency caused by the HAMI-based charge.

### D.2 Methodology for assessing possible generation investment inefficiency

D.2.1 The potential investment inefficiency arises from the fact that the HVDC cost recovery provides an additional locational signal (discouraging new SI generation investment) which does not reflect any marginal costs since the HVDC investment is committed and utilisation of the existing and new link will be fully reflected in market prices (through loss and congestion components of nodal prices in the wholesale market)<sup>129</sup>.

D.2.2 This appendix describes a simplified analysis<sup>130</sup> of the possible increase in present value of future new generation investments (arising from the HVDC charge) using the following methodology:

- A simple merit order of new generation base load and renewable investments is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options<sup>131</sup>;
- The new generation investments are ranked on the basis of a simple long-run marginal cost (LRMC) measure including capital recovery, fixed and variable operating costs, fuel and Emissions Trading Scheme (ETS) costs, and approximate location factors (reflecting marginal losses) and intermittency factors<sup>132</sup>;
- A merit order without the HVDC charge is constructed and used to derive a new investment schedule and LRMC profile to cover demand growth and plant retirement out to 2050;
- The same approach is used to derive a merit order, new investment schedule, and LRMC profile while including the HVDC charge for SI generation options;

<sup>129</sup> The additional locational signal may possibly reflect a true marginal cost beyond 30 years when another HVDC investment may be required to either upgrade the capacity of the link to maintain the capacity when the existing pole 2 reaches the end of its economic life.

<sup>130</sup> This simplified analysis is able to address some of the concerns raised by submitters with respect to the GEM model and analysis (see appendix C). While approximate, the analysis is very transparent, and enables a full set of sensitivities to be explored.

<sup>131</sup> This analysis uses plausible assumptions developed from a combination of sources including the Commission (used in GEM analysis) and MED. The list of potential new projects is based on the GEM database of base load and renewable projects used by the Commission in the earlier analysis with some modifications reflecting cost. This includes 960MW of new NI geothermal, 2,900MW of NI wind projects and 1,360MW of SI wind projects, 470MW of NI hydro options and up to 2,240MW of SI hydro, 310MW of NI cogeneration and 42MW of SI cogeneration.

<sup>132</sup> The LRMC used here is the levelised average real time-weighted average future price at Haywards necessary to cover the full costs of the new investment option being considered over its life-time. The intermittency factors take into account that different projects achieve different generation weighted-average prices from time-weighted prices..

- The potential economic cost is estimated by calculating the increase in present value cost between the two scenarios for a base case scenario and for one with additional gas supply at a lower gas price<sup>133</sup>.

D.2.3 It should be noted that this appendix only considers the possible generation investment inefficiency arising from HVDC cost recovery. It does not consider, or attempt to quantify, the possible benefit of deferring or preventing investment in a new or expanded HVDC link, or the possible benefit of deferring AC transmission upgrades necessary to support an expanded HVDC link. The analysis only considers generation options that can be accommodated within the committed capacity of the HVDC.

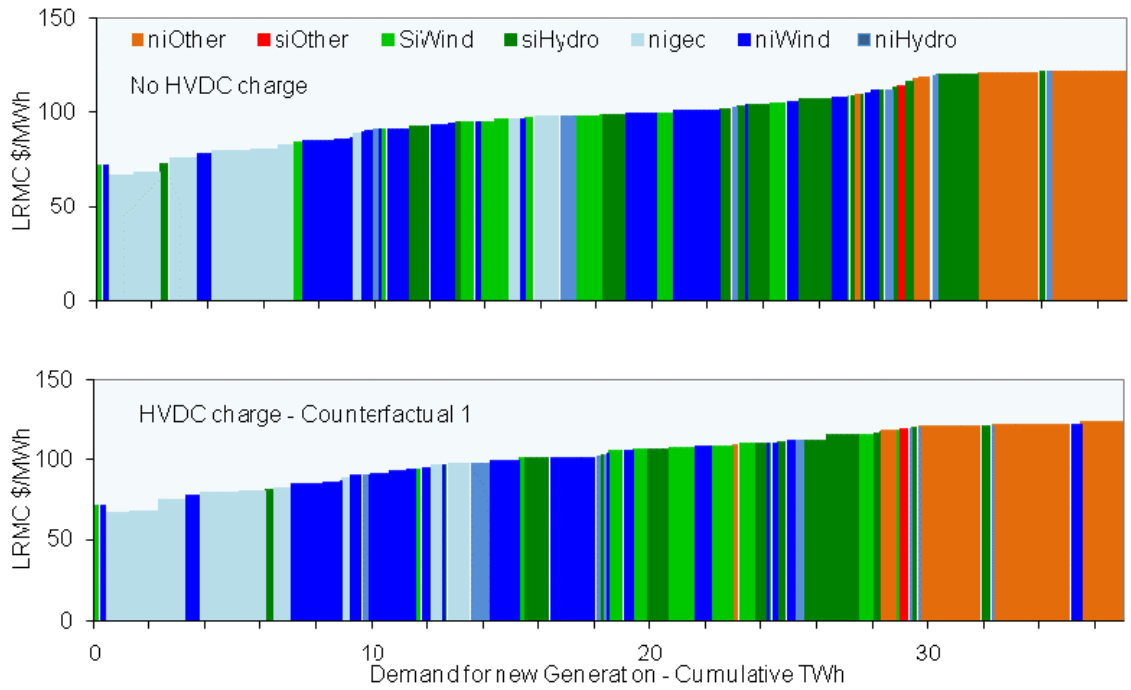
### D.3 Constructing the merit order

- D.3.1 There is a merit order of future new generation projects that are available to meet the growing demand for electricity. It is difficult to know exactly what this merit order is because it depends on a whole range of factors (capital and fuel prices, resource availability, exchange rates, and discount rates, for example). Although there are many factors that influence the sequence of development for new generation, it is reasonable to assume that new projects generally proceed according to a rough order of cost with the cheapest projects proceeding first.
- D.3.2 For this analysis it is not especially important what the exact merit order is. What is important is the potential cost of changing the merit order through the application of HVDC charges on SI generation projects.
- D.3.3 Figure 9 illustrates the two different merit orders used in this analysis, highlighting that a range of geothermal and wind projects appear to provide the cheapest development options<sup>134</sup>. Note that 10 TWh represents approximately 25% of today's annual electricity demand.
- D.3.4 The potential impact of the HVDC charge on the merit order is illustrated by the change in the chart 'No HVDC charge' to 'HVDC charge – Counterfactual 1'. Note that, in this example, a number of SI wind and hydro projects are delayed as a result of the HVDC charge.

<sup>133</sup> The base case scenario assumes that gas supply remains limited, and there is a \$40/t carbon price, a \$13/GJ gas price, \$4.5/GJ coal price in real 2010 terms. Under this scenario existing Combined Cycle Gas Turbine (CCGT) capacity is maintained and most new capacity is geothermal, hydro or wind over the next 30 years. The low gas cost scenario is based on a significant new gas discovery at \$8/GJ which would support some additional CCGT gas plant beyond 2025.

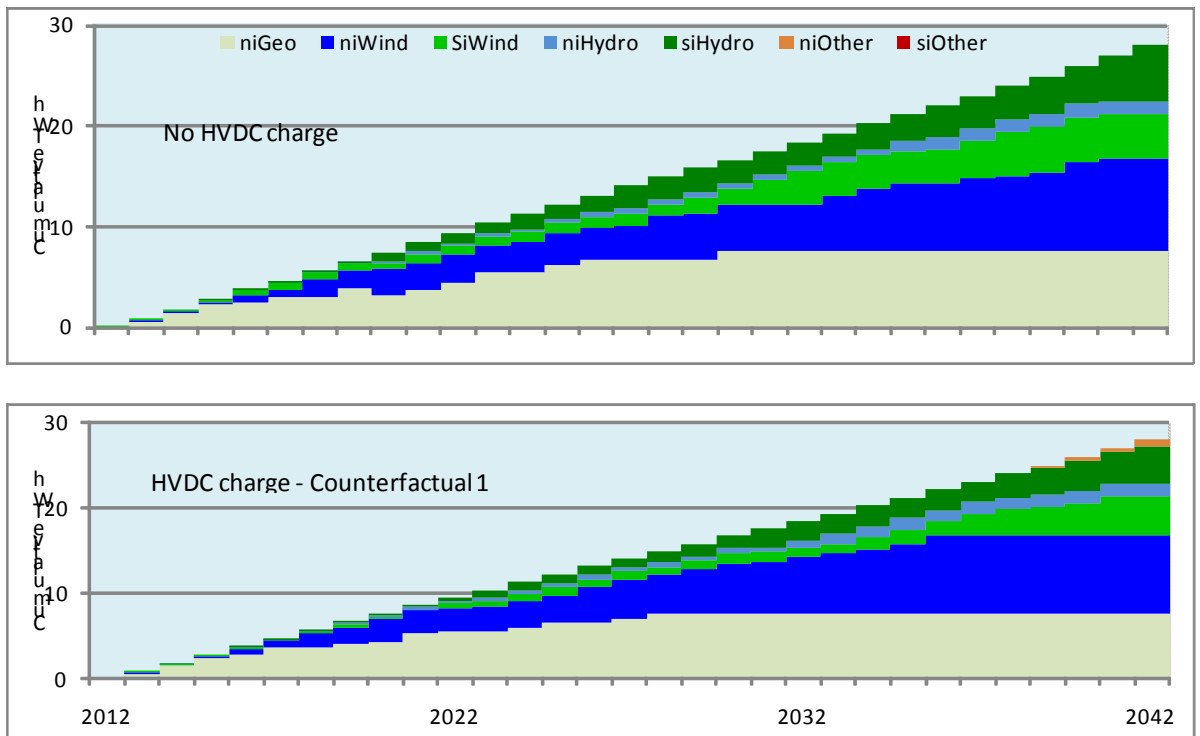
<sup>134</sup> The long run marginal costs have been estimated using an assessed weighted-average-cost-of-capital (WACC) of 7% real post-tax. This reflects a typical nominal commercial post tax rate of return required by generators adjusted for inflation.

**Figure 9 Illustrative merit order of new generation projects (\$/MWh)**



D.3.5 This is further highlighted in Figure 10 which illustrates the timing of new generation under the two scenarios. The impact of the HVDC charge in this example is to defer some SI hydro and wind developments relative to NI projects.

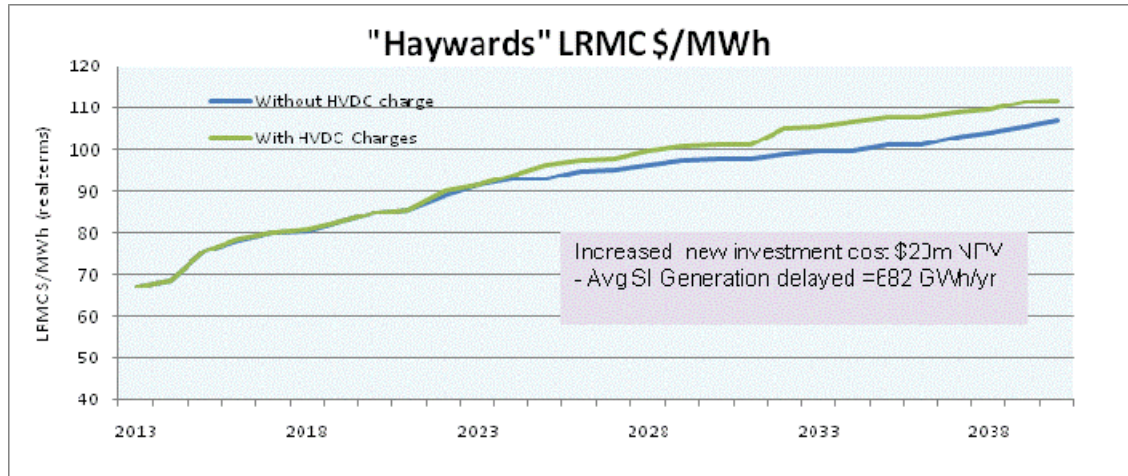
**Figure 10 Illustrative impact on timing of investment**





- D.3.6 Figure 11 illustrates the potential impact on the LRM curve which tends to feed into wholesale electricity prices. The LRM curve is derived at the Haywards location by referring all projects to that point using the assumed average location factor for each project.
- D.3.7 Note that in this example LRM is up to \$8/MWh higher in some years. This would likely flow through to wholesale electricity prices and possibly impact upon NI/SI price differentials.

**Figure 11 Impact on the LRM curve**



#### D.4 Sensitivity analysis

- D.4.1 An estimate of the economic cost has been determined by calculating the difference in the net present value of investment between the two scenarios over 30 years using a 9% real pre tax discount rate<sup>135</sup>.
- D.4.2 It is assumed that the average net HVDC cost under the existing price structure is \$35/kW/yr in real 2011 dollar terms<sup>136</sup> for the 15 years following the commissioning of pole3 if SI generators continue to receive the value of HVDC rentals.
- D.4.3 The analysis of economic costs is dependent on a number of assumptions including; new investment costs, fuel costs and availability, exchange rates and other factors. These cannot be known with certainty in advance and so a combination of scenario and sensitivity analysis is used in the analysis.
- D.4.4 A standard scenario approach is used to account for the impact of alternative 'states of the world'. However the impact of an HVDC charge also depends on the relativity between individual renewable projects such as wind and hydro. These will vary significantly from site to site depending on; the quality of the resource, the cost of connection to the grid, the resource

<sup>135</sup> Note that a 9% real pre-tax rate is approximately consistent with the 7% real post-tax rate used to assess the commercial return typically required for new generation.

<sup>136</sup> In reality the gross HVDC charge (in real 2011 terms) is expected to be around \$45/kW/yr in 2013 and then fall to around \$40/kW/yr by 2020, and then continue to fall in real terms as a result of the accounting rules used in setting the revenue requirement. Currently parties paying HVDC charges receive HVDC rentals. A study by Energy Link prepared for the Electricity Authority in March 2011 estimates these to be worth around \$4-6/kW/yr following the commissioning of pole 3. The net HVDC cost is thus around \$35/kW/yr over the 15 years following pole 3. The possibility that payers of HVDC charges do not receive the value of these rentals is treated as sensitivity.

consent limits and the international costs of generators and turbines at the time that these projects are committed. These cost variations can't be known now and will only become apparent during the process of project investigation, planning and resource consenting.

- D.4.5 Each scenario uses a list of potential projects that was developed by the Commission for the Statement of Opportunities (SOO) published in September 2010 and used by the Ministry of Economic Development in its Energy Outlook published in December 2010. This list of potential projects has been developed over a number of years and has been consulted on and used in modelling work for transmission investments and other electricity sector issues. The list of projects includes around 960MW of NI geothermal, 2900MW of NI wind and 1360MW of SI wind, 470MW of NI hydro and up to 2240MW of SI hydro, 310MW of NI cogeneration and 42MW of SI cogeneration. Much of the hydro is relatively high cost. It also includes a number of NI gas fired thermal options which may be viable if there is sufficient local gas available as a reasonable cost. Additional coal fired options are also possible based on SI, NI or imported resources and may be viable if coal prices and carbon prices are low enough, but this is not considered likely. There are numerous peaking options, but these are not used in this analysis as it focuses on new projects to meet the demand for 'energy' rather than peaks. The typical level of costs of these projects and the earliest commissioning has been updated to reflect more recent information.
- D.4.6 The typical capital cost levels are assumed to be; \$2300 to \$2500/kW for wind, \$3000 to \$6000/kW for hydro, \$4700 to \$5200/kW for geothermal, \$1750/kW for CCGTs and \$3000/kW for coal. As discussed above, these costs are still subject to considerable uncertainty which is accounted for through the scenario and sensitivity analysis. In each scenario it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge.
- D.4.7 The base case scenario assumes that gas supply remains limited, and there is a \$40/t carbon price, a \$13/GJ gas price, \$4.5/GJ coal price in real 2010 terms. Under this scenario existing CCGT capacity is maintained and most new capacity is geothermal, hydro or wind over the next 30 years.
- D.4.8 The low gas cost scenario is based on an assumed increased supply in natural gas at \$8/GJ (real) sufficient to support some additional CCGT gas plant beyond 2025 in the NI.
- D.4.9 The base case and low gas cost scenarios assume that exchange rates revert to long run averages, 0.6 for the USD:NZD cross rate and 0.5 for the Euro:NZD cross rate. An additional sensitivity using current exchange rates is also explored.
- D.4.10 The analysis accounts for the individual project cost variation by randomly sampling project capital costs. Ten separate cases were evaluated with individual project costs being randomly varied by  $\pm 20\%$  around a generic capital cost for each general class of investments (geothermal, wind, hydro thermal etc).
- D.4.11 The results are reported in Table 41.

**Table 41 Generation Investment inefficiency with a HAMI charge- Sensitivity Analysis**

HVDC Cost	\$35/kW	Economic Cost \$m PV	
Sensitivity		Base Case	Low Gas cost Scenario
Current Exchange rates		\$18m	\$25m
Long run Exchange Rates		\$16m	\$25m
Random Capex 1		\$34m	\$37m
Random Capex 2		\$37m	\$41m
Random Capex 3		\$27m	\$30m
Random Capex 4		\$28m	\$38m
Random Capex 5		\$27m	\$43m
Random Capex 6		\$45m	\$51m
Random Capex 7		\$17m	\$25m
Random Capex 8		\$14m	\$20m
Random Capex 9		\$42m	\$47m
Random Capex 10		\$30m	\$29m
Average		\$28m	\$34m

- D.4.12 The sensitivity analysis undertaken for a \$35/kW/yr HAMI cost suggests an economic cost in a band of \$14m to \$51m (average \$31m).
- D.4.13 The lower end of the range of the economic cost applies in sensitivities where there is a large quantity of NI generation options that have a lower cost than SI options and hence the HVDC cost allocation does not have a significant impact for a number of years. In all cases it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. Hence the lower levels of economic cost arise from there being a significant block of cheaper NI wind. Note that approximately twice as much potential wind is assumed to be available in the NI as in the SI and hence there is the potential for a delay in the impact of the HVDC charge if much of this NI resource is cheaper than the SI.
- D.4.14 The upper range of economic cost applies in other sensitivities where there are some SI options which are of a similar or lower cost to NI options and hence the HVDC cost allocation results in a much more significant delay from an earlier date. This can also occur in the scenario where it is assumed that there is sufficient local gas supply available for additional CCGT projects in the NI beyond 2025 that have a similar cost to NI and SI renewable options. In this case an HVDC charge

could delay cheaper SI renewable options by many years and hence result in a higher present value cost.

## D.5 Change from HAMI cost allocation

- D.5.1 The alternative MWh charge option described in Table 14 has been suggested as a means of reducing any possible economic inefficiency from charging HVDC costs to SI generators. Recovering the same revenue over all SI generation could be achieved with a \$7/MWh cost instead of a \$35/kW HAMI cost.
- D.5.2 The investment inefficiency analysis has therefore been repeated with a \$7/MWh net cost. The results are summarised in Table 42 which confirms that the economic inefficiency is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh net cost rather than HAMI<sup>137</sup>.

**Table 42 Generation Investment Inefficiency with a \$7/MWh HVDC cost**

HVDC Cost \$7/MWh	Economic Cost \$m PV		Difference from HAMI	
	Base Case	Low Gas cost	Base Case	Low Gas cost
Current Exchange rates	\$12m	\$13m	-\$6m	-\$12m
Long run Exchange Rates	\$10m	\$18m	-\$6m	-\$7m
Random Capex 1	\$19m	\$20m	-\$15m	-\$16m
Random Capex 2	\$28m	\$33m	-\$9m	-\$8m
Random Capex 3	\$22m	\$24m	-\$5m	-\$6m
Random Capex 4	\$22m	\$30m	-\$6m	-\$8m
Random Capex 5	\$16m	\$20m	-\$11m	-\$23m
Random Capex 6	\$20m	\$22m	-\$25m	-\$29m
Random Capex 7	\$14m	\$22m	-\$3m	-\$3m
Random Capex 8	\$9m	\$14m	-\$5m	-\$6m
Random Capex 9	\$24m	\$26m	-\$18m	-\$21m
Random Capex 10	\$23m	\$26m	-\$8m	-\$4m
Average	\$18m	\$22m	-\$10m	-\$12m

<sup>137</sup> Note that there are additional economic inefficiencies associated with the HAMI price structure relating to the incentives it provides to withhold capacity from the SI market and to discourage incremental SI peaking capacity. These are quantified in D.9.

- D.5.3 The sensitivity analysis for a \$7/MWh HVDC cost suggests an economic cost in a band of \$9m to \$33m (average \$20m).
- D.5.4 The reason why the economic cost is lower in this case is that the inefficiency mainly relates to delays in SI wind and hydro and these projects typically have capacity factors in the order of 35-50%. A HAMI allocation would imply a \$9-\$11/MWh disadvantage for SI projects, whereas this is reduced to \$7/MWh under a MWh allocation.

## D.6 Cost of HVDC charges to Incumbent SI Generators

- D.6.1 The analysis above is based on a \$35/kW/yr or a \$7/MWh HVDC cost facing new entrant generators in the South Island. However incumbent generators may not face the same cost as a new entrant when making an investment in SI generation.
- D.6.2 The issue arises because the incremental HVDC cost applying to a new investment in the SI can be lower for incumbent generators who pay a high proportion of the costs. This is because total HVDC charges are fixed and any new investment in SI generation will result in a reallocation of the charges between the incumbent generators and new generators. A completely independent new SI generator will see the full incremental HVDC cost for its new generation (\$35/kW/yr), but all the incumbents will benefit from a reduction in their share of the costs. The extent to which large incumbent generators have an advantage relative to new entrants depends upon both its share of the HVDC costs and the investment 'counterfactual' which applies.
- D.6.3 Under counterfactual 1 it is assumed that new SI investment by an incumbent SI generator would displace other similar SI generation. In this case the SI incumbent will benefit from reduced HVDC charges regardless of whether it or a competitor builds new generation, and it can be demonstrated that the incremental HVDC charge it would face, in respect of the new generation, would be the same as competitors.
- D.6.4 Under counterfactual 3 it is assumed that new SI investment by an incumbent SI generator would not displace other similar SI generation. In this case the SI incumbent will benefit from reduced HVDC charges if it proceeds with the new generation and it will have an advantage relative to small incumbents and new entrants.
- D.6.5 In practice one cannot be certain about what would occur in the absence of a new investment by one of the incumbent SI generators, and different incumbents are likely to make different assumptions about what is likely and what their cost relative to a competitor's cost will be.
- D.6.6 It can be shown<sup>138</sup> algebraically that the incremental HVDC cost for an incumbent investing in the South Island is somewhere between 100% of the full HVDC cost (\$35/kW/yr) and (100% less its existing cost share<sup>139</sup>) times the full HVDC cost, depending on the investment counterfactual. Counterfactual 2, lying between the two extremes, has therefore been developed for the purpose of this analysis.
- D.6.7 The potential counterfactuals and the impact on the largest incumbent (Meridian Energy with 70% share of HVDC charges) are described in Table 43.

<sup>138</sup> For example see Appendix to Q5 of Norske Skog submission on Transmission Pricing Review (Sep 2010). Available at: <http://www.ea.govt.nz/document/11150/download/our-work/consultations/transmission/tpr-stage2options/submissions/>

<sup>139</sup> This is the share of the total HVDC costs that a particular SI incumbent is paying prior to making a new investment in the South Island. Typically this would be around 70% for Meridian, 22% for Contact, 6% for Genesis and 2% for TrustPower.

**Table 43 SI generation investment counterfactuals and impact on Meridian Energy**

Option	Description	Meridian's net incremental cost from HVDC charge
<b>Counterfactual 1</b>	Large incumbent generator assumes that if it invests in the SI it will displace a competitor investment in the SI.	\$35/kW/yr
<b>Counterfactual 3</b>	Large incumbent generator assumes that if it invests in the SI it will displace a NI investment and will have no impact on a competitor investment in the SI.	\$11/kW/yr =(100%-70%)*35
<b>Counterfactual 2</b>	In practice, the large incumbent generator will be uncertain about the outcomes and the effective HVDC cost will likely lie between Counterfactual 1 and Counterfactual 3. For counterfactual 2 it has been assumed that the cost impact is half way between the two extremes.	\$23/kW/yr

D.6.8 Table 44 summarises the results of the simplified analysis taking into account the different counterfactuals and suggests that the economic efficiency loss associated with the HVDC charge could be between \$11m and \$51m. Note that the loss appears to be highest for counterfactual 1 (where investment by the incumbent displaces other SI generation) and lowest for counterfactual 3 (where investment by the incumbent displaces NI generation). This is because, under counterfactual 3, Meridian faces a lower effective HVDC cost and hence its projects will not be delayed as much as under counterfactual 1<sup>140</sup>.

**Table 44 Economic cost of HVDC charge**

Counterfactual	Meridian's HVDC incremental cost	Average Economic cost (NPV)	
		Base Case	Low gas cost
<b>1. Displaces SI generation</b>	\$35/kW/yr	<b>\$28m</b> (\$14-\$45m)	<b>\$34m</b> (\$20-\$51m)
<b>2. Intermediate</b>	\$23/kW/yr	<b>\$23m</b> (\$12-\$36m)	<b>\$28m</b> (\$18-\$39m)
<b>3. Displaces NI generation</b>	\$11/kW/yr	<b>\$19m</b> (\$11-\$32m)	<b>\$23m</b> (\$15-\$36m)

<sup>140</sup> Note that the Commission carried out experiments to estimate the economic cost of generation investment inefficiencies arising from the HVDC charge as outlined in Appendix 4 of the Transmission Pricing Review: Stage 2 Options, July 2010, available at: <http://www.ea.govt.nz/document/9994/download/our-work/consultations/transmission/tpr-stage2options/>. This was derived using the GEM model and resulted in cost estimates of \$6-36m (average \$16m). These results are broadly similar, but are not strictly comparable with this updated analysis as this earlier work used a lower HVDC cost of \$30/kW/yr, assumed counterfactual 3 only, used lower discount rates to rank generation projects, imposed higher capacity margins than the standard and used outdated capital cost estimates and efficiencies for some plant types.

- D.6.9 However, note that under counterfactual 3 Meridian has a \$26/kW (\$35 less \$11) advantage over other SI competitors and, if this was the case, it could lead to Meridian increasing its dominance in the SI. This reduction in competition would likely lead to additional efficiency losses not accounted for in this analysis.
- D.6.10 It is not possible know which counterfactual will apply over the next 30 years. It seems likely that it will be closer to counterfactual 3 than 1 in the short run given that SI options are competing directly with relatively low cost NI generation options (e.g. geothermal). Once the relatively cheap NI geothermal options have been fully developed, counterfactual 2 is more likely as SI generation options (such as wind and hydro) compete with similar cost projects in the NI. Counterfactual 1 would apply if there is a band of SI generation options which are all clearly cheaper than the lowest cost NI options, or there has been so little investment in the SI that SI reliability is threatened and new capacity is required in the SI.
- D.6.11 Most reliance is placed on the analysis results for counterfactual 1 which does not provide Meridian an artificial competitive advantage. This assumes that the cost of Meridian increasing its dominance in the SI offsets any reduction in the generation investment inefficiency with counterfactuals 2 and 3.

## **D.7 HVDC rental allocation sensitivity**

- D.7.1 The Authority is consulting on a locational risk management proposal which involves Financial Transmission Rights (FTRs) between Benmore (BEN) and Otahuhu (OTA) being made available to market participation through regular auctions. These FTRs would be supported by loss and constraint rentals on the HVDC and on lines from Haywards (HAY) to OTA collected through the settlement system.
- D.7.2 If this proposal is implemented SI generators paying for HVDC assets would no longer get HVDC rentals as they did in the past. In the September 2010 consultation paper it was proposed that net proceeds from the FTR auctions (residual FTR revenue) would be allocated to transmission customers according to the TPM. This would mean that SI generators paying for HVDC assets would, in principle, continue to receive the share of residual FTR revenue that related to the HVDC.
- D.7.3 In theory the residual FTR revenue should be approximately equal to the expected future value of the BEN to OTA net rentals. However it is proposed that there be a 6 month lag in allocating revenues, and that some revenue may be retained in the FTR account to support revenue adequacy. This may affect the value to recipients. There will also be issues relating to the allocation of auction proceeds between HVDC and other assets used to support the BEN-OTA FTRs, as there will not be a market based contract value for the HVDC rental stream.
- D.7.4 In addition the Authority is concerned that there could be competition issues if parties who participate in FTR auctions also receive a significant share of the proceeds. For this reason it is considering other options for allocating the residual FTR revenue. In some of the options SI generators who pay for HVDC assets would no longer receive the value of HVDC rentals.
- D.7.5 Sensitivity analysis is used to deal with this uncertainty. The base case analysis assumes that SI generators continue to get the full value of HVDC rentals and hence the net HVDC cost is equal to approximately \$35/kW/yr which equals the gross HVDC charge (approximately \$40/kW/yr) minus the expected value of the HVDC rentals post pole 3 (approximately \$4-6/kW/yr ). The alternative

sensitivity assumes that SI generators get no HVDC rentals and hence the HVDC cost is the full \$40/kW/yr.

- D.7.6 Table 45 shows the economic cost of HVDC charges (under counterfactual 1) in the event that SI generators receive no rentals, and hence face the full gross HVDC charges of \$40/kW/yr.

**Table 45 Generation Investment Inefficiency from HVDC charges without rentals.**

HVDC cost allocation	HVDC cost	Average Economic cost (NPV)	
		Base Case	Low gas cost
HAMI Allocation	\$40/kW/yr	\$33m (\$19-\$54m)	\$42m (\$27-\$64m)
MWh Allocation	\$8/MWh	\$22m (\$10-\$33m)	\$28m (\$15-\$36m)

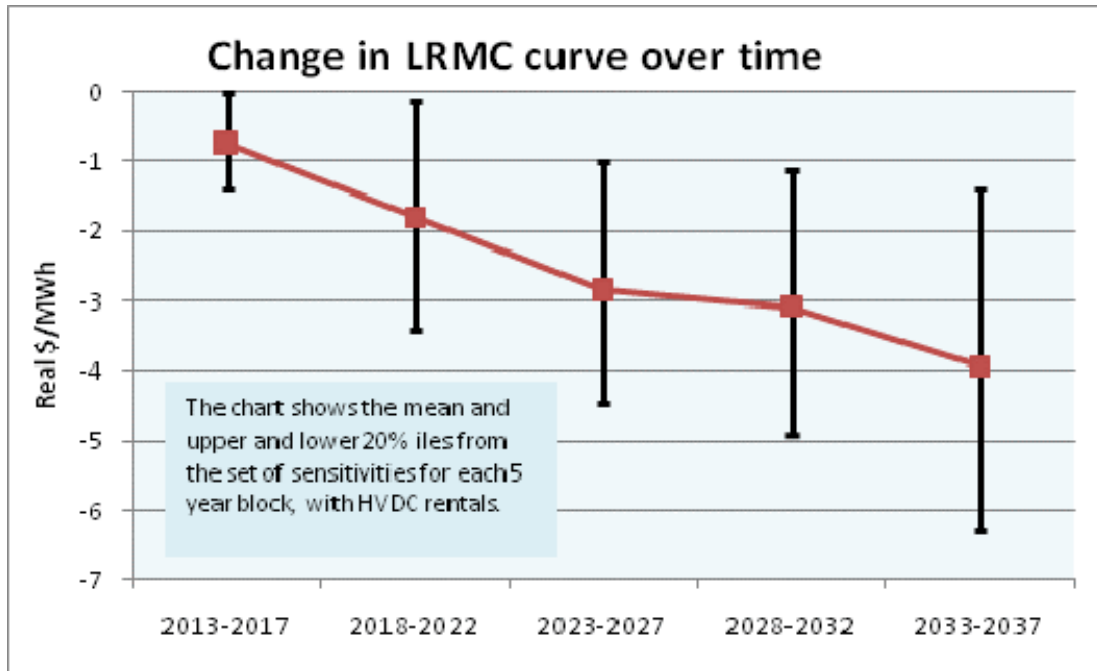
- D.7.7 In this case the generation investment inefficiency is increased by around \$6 to \$8m to approximately \$19-\$64m (average \$38m) for a HAMI allocation and \$10-\$36m (average \$26m) under a MWh allocation.

## D.8 Potential value impact on end use customers

- D.8.1 A shift of HVDC cost recovery from SI generators to customers will result in a higher delivered price to end-use customers in the short run. This is likely to be offset by reductions in wholesale prices resulting from the reduction in the LRMC of new SI generation options.
- D.8.2 The extent of this wholesale price impact can be approximated using the same merit-order approach used to estimate the generation investment inefficiency. The chart below shows the mean and percentiles of the 5 year average LRMC reduction resulting from removal of HVDC charges on new SI generation. These estimates are derived by recording the LRMC impact from 96 sensitivities (including randomly varying individual new generator capital costs with the base case scenario, a limited geothermal scenario and a low gas cost discovery scenario).



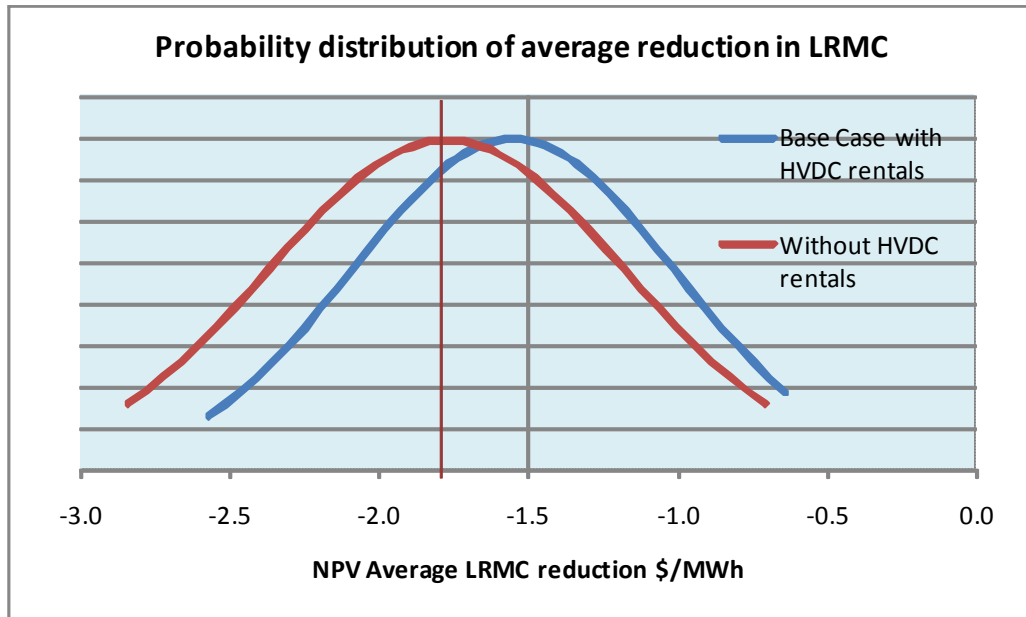
Figure 12 Impact of Removal of HVDC charges on the NZ LRMC Curve



- D.8.3 As can be seen the impact on the NZ LRMC is relatively low initially but gets greater over time. This reflects the fact that the LRMC is mainly set by low cost NI geothermal options over the next 5 years or so, but then can be set by either NI or SI generation options depending on their cost.
- D.8.4 The uncertainty in the impact is illustrated by the upper and lower percentiles of the distribution of sensitivities shown in the chart. The impact is relatively less certain over time.
- D.8.5 The present value average impact on the LRMC is illustrated in the chart below<sup>141</sup>. This has a mean of approximately  $-\$1.5/\text{MWh}$  and a standard deviation of around  $\$0.5/\text{MWh}$ .

<sup>141</sup> The present value average impact is derived by taking the present value of the annual impacts over 20 years at a 9% real pre tax discount rate and dividing by the uniform series present worth factor.

Figure 13 The Probability distribution of the PV impact on LRMC



D.8.6 This figure also shows the impact in the case where SI generators receive no value from the HVDC rentals. The impact on LRMC is approximately \$0.2/MWh greater in this case.

## D.9 Potential peaking generation investment inefficiency

D.9.1 The analysis above considered the potential base load and renewable generation investment inefficiency arising from the HVDC cost allocation. There is also the potential for peaking generation investment inefficiency as a result of the HAMI cost allocation methodology.

D.9.2 This potential inefficiency can arise if the HAMI pricing structure results the delay of cheaper SI peaking generation investment and the bringing forward of more expensive NI peaking generation.

D.9.3 This potential peaking investment inefficiency was estimated to be \$0-25m in earlier work carried out by the Electricity Commission (Appendix 4 to the Stage 2 Consultation paper) and is updated here.

D.9.4 For SI peaking capacity to have value in the NI it is necessary that there is sufficient firm capacity on the HVDC to transfer the excess SI peaking capacity (above SI peak demand) to the North Island. Figure 14 below is derived from the 2011 Annual Security Assessment (ASA) published by the System Operator in Jan 2011. This shows the measures of SI peak demand<sup>142</sup> and SI capacity supply as used in capacity margin assessments. Also shown is the maximum firm SI capacity that can be transferred across the HVDC. This accounts for losses and NI instantaneous reserve requirements<sup>143</sup>. Three components of the SI peak generation capacity are shown. The base level

<sup>142</sup> The capacity margins in the ASA use a measure of peak demand which is the average of the top 200 trading periods. This is adjusted by an empirical allowance of 130MW for SI reserves and NI/SI demand diversity etc. The contribution to peak capacity uses derating factors which accounts for plant outage risk and intermittency.

<sup>143</sup> Prior to pole 3 the maximum transfer capability into the NI is around 660MW. This is the maximum that can be transferred without increasing the contingent event risk associated with the largest generation in the North Island (around 400MW). Once

is that used in the ASA which includes the existing SI generation plant as it is currently offered to the market. It only includes 680MW of the full 752MW from the Clutha scheme as Contact is restricting the capacity to avoid HVDC charges. The additional MW peaking capacity available from the Clutha and Manapouri schemes<sup>144</sup> and other new SI renewable generation that might be built is also shown. The particular profile of new SI generation capacity shown in the figure is illustrative only and is based on the new capacity without an HVDC charge from sensitivity 4 in Table 41. The chart also includes an additional 200MW peak capacity that might be available at relatively low cost from upgrades to existing SI hydro plant. This potential was identified in the earlier work carried out by the Electricity Commission.

- D.9.5 The figure shows that until pole 3 is commissioned there is excess SI peak generation capacity. This means the full value of SI peaking capacity cannot be realised and may explain why SI generators are currently withholding peak capacity from the market to avoid HAMI HVDC charges. Once pole 3 is commissioned the current excess of SI peaking capacity can be transferred over the HVDC and will have significantly more value in the North Island. It is expected that the NI value will exceed the HAMI charge and hence it should be economic to offer most or all of the existing SI peaking capacity into the market even if HAMI HVDC charges remain.
- D.9.6 There appears to be adequate HVDC transfer capacity (at least for the next 10yrs) to accommodate the likely SI generation build and an extra 200MW of existing capacity upgrades, if these were available a lower cost than NI peaking capacity. Additional firm HVDC capacity might be available if there is short run overload capacity on pole 2 and an extra 200MW could also be available if an additional submarine cable was built but this may involve a national cost of up to \$60/kW/yr<sup>145</sup>.

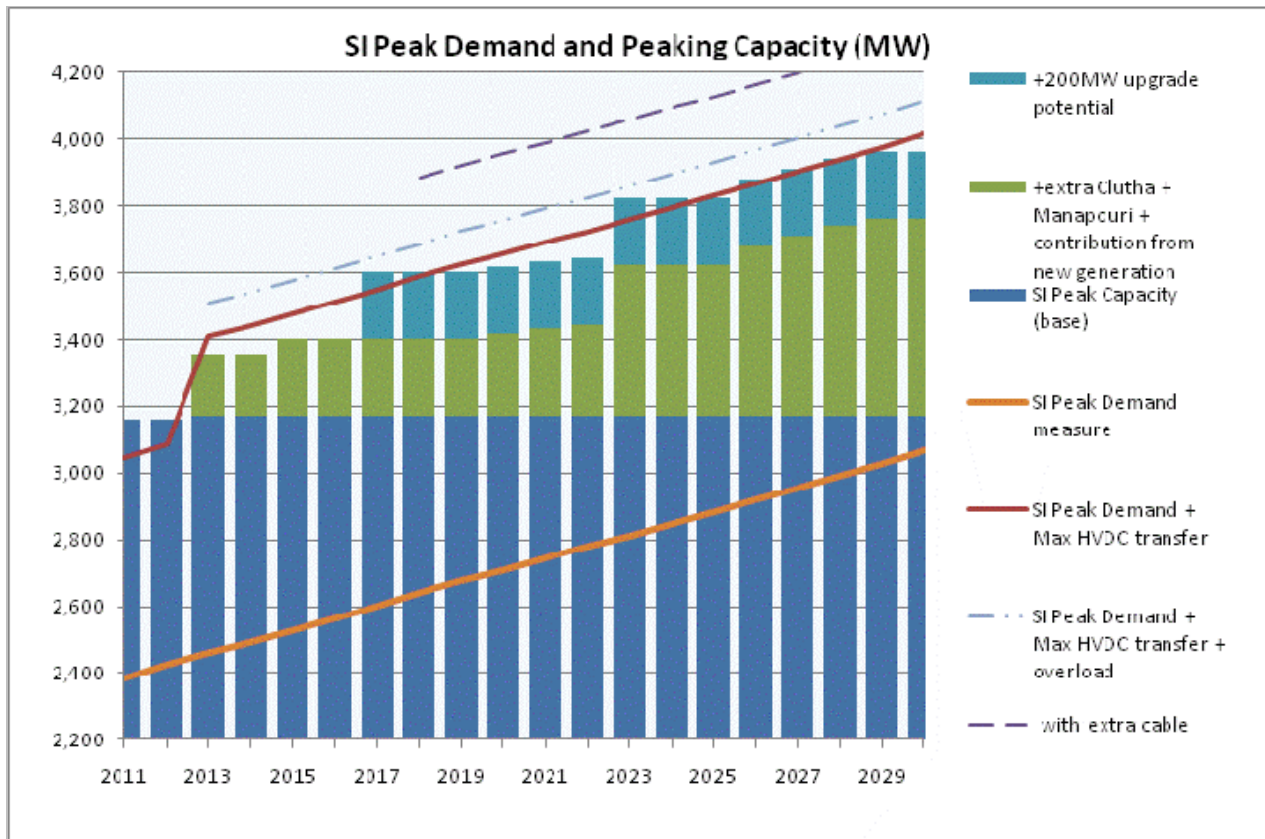
**Figure 14 Expected peak supply and demand in the South Island**

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pole 3 is fully commissioned to 1200MW this limit is increased to 900MW, which is achieved by operating the 500MW pole at 400MW and the 700MW pole at 500MW. In this configuration the loss of the larger 500MW pole is partly covered by the other pole increasing from 400MW to the maximum 500MW and so the net contingent event risk is only 400MW (ie 500MW-100MW self cover). It is possible that some additional short term overload capacity may be available as well, but this is not certain. There will be other times when additional SI peak capacity can be sent north, but this relies on there being NI instantaneous reserves available at a reasonable price. An addition 200MW of firm capacity could be made available by installing an additional submarine cable and filters, but this is not committed and would involve a capital cost of around \$125m(see footnote 145). The potential impact of this is shown in the figure.

<sup>144</sup> Manapouri received revised resource consents in July 2010 to enable it to operate up to its installed capacity of 840MW, subject to possible operational and transmission constraints.

<sup>145</sup> Transpower indicate a \$125m real capital cost for an additional cable and associated filters (2011 dollar terms) and this may provide around 200MW of additional firm transfer capacity. The cost of this is \$625/kW (\$125m/.2MW), which would be approximately \$60/kW/yr with an 8% real pre-tax discount rate and 25 year life. This could be an over estimate if the additional cable is partly justified by other factors such as the back-up value to cover failure of one of the other cables.



D.9.7 There is a potential peak generation investment inefficiency arising from the HAMI charge if this results in cheaper SI peaking capacity (from existing plant upgrades or reconfiguration of new SI generation<sup>146</sup>) being delayed, and as a result more expensive NI peaking capacity is required to meet NZ capacity margins. For this inefficiency to arise the SI peaking enhancements would need to be commercially justified without a HAMI charge, and not justified with the HAMI charge. This means that the SI peak upgrade options need to be between \$0 and \$35/kW/yr<sup>147</sup> cheaper than the SI equivalent cost of NI peaking options<sup>148</sup> that could be deferred. Note that if a SI upgrade option was greater than \$35/kW/yr cheaper than the NI peaking options then the SI option would be commercially justified with or without the HAMI charge and so there would be no investment inefficiency.

D.9.8 The potential inefficiency depends on the quantity of upgrade capacity available in the SI, the number of years that NI peaking capacity is deferred without having to incur the cost of an

<sup>146</sup> For most new SI generation options it is possible to adjust the balance between energy and peaking capacity within some bounds. The HAMI charge structure tends to discourage adding additional capacity.

<sup>147</sup> Note that this analysis assumes SI generators would continue to get the value of HVDC rentals and counterfactual 1 holds as discussed in D.6.3. This will result in a higher estimate of inefficiency, but avoids having to estimate the cost of Meridian increasing its dominance in the SI.

<sup>148</sup> The expected cost of new peaking capacity in the North Island is estimated to be in the range \$130 to \$150/kW/yr based on new oil fired peaking capacity. Even without HVDC charges SI peaking capacity has a lower value in the North Island due to losses across the HVDC and the risk of bipole failure. The value of SI capacity close to or above the level indicated by the red line in the chart will fall significantly as this would require additional NI instantaneous reserve. Given this, SI peak capacity may need to have a cost around \$100/kW/yr to displaced NI peaking capacity without an HVDC charge. Thus the SI peak upgrade options would have to fall in the range of \$65-\$100/kW/yr for there to be a peaking investment inefficiency arising from the HAMI charge.

additional cable, and where in the range \$0-\$35/kW/yr the cost difference falls. The figure above indicates that NI capacity could be deferred 15 years; however this depends on the scenarios for new SI generation build without a HAMI charge and on SI demand growth. The extent of deferral could range from 5 to over 15 years.

- D.9.9 Table 46 shows the estimated peaking generation inefficiency for an assumed 200MW upgrade capacity for a range years of deferral and cost differences.

**Table 46 Potential peaking investment inefficiency from the HAMI cost allocation**

MW SI Upgrade	200MW		
Cost Difference \$/kW/yr (real)	\$0/kW/yr	\$18/kW/yr	\$35/kW/yr
Years of Delay	2011 NPV Inefficiency \$m <sup>149</sup>		
5 yrs	\$0	\$9	\$18
10 yrs	\$0	\$15	\$29
15 yrs	\$0	\$18	\$37

- D.9.10 This analysis indicates that there could be up to \$37m peaking investment inefficiency arising from the HAMI HVDC cost recovery mechanism, if there is 200MW of SI peaking upgrade capacity available from existing hydro generation in the SI which is up to \$35/kW/yr lower cost than NI peak generation options. This maximum peaking investment inefficiency would be around 15% higher (\$42m) if the SI generators don't get the value of HVDC rentals.
- D.9.11 While it is plausible that there could be up to 200MW of additional peak upgrade capacity (for example there is scope to add additional turbines to the Clyde station and there could be additional mid-life refurbishment at some of Meridian and TrustPower's schemes over the next 10-20 years), it is not known if the effective cost of increasing peaking capacity would be in the required range if and when these options become available. The analysis shows there is a clear risk that the HAMI cost allocation methodology might result in a significant investment inefficiency, but it is not possible to be certain of this.

<sup>149</sup> This assumes that the 200MW could be provided in 2017. A 9% pre-tax real discount rate is used, consistent with that used to evaluate other generation investment inefficiencies.



## Glossary of abbreviations and terms

<b>AC</b>	Alternating Current
<b>ACI</b>	Asset Concentration Index. This is used to calculate a threshold for allocating costs using flow tracing.
<b>Act</b>	Electricity Industry Act 2010
<b>ASA</b>	Annual Security Assessment published by the System Operator.
<b>Authority</b>	Electricity Authority
<b>Capex IM</b>	The Commerce Commission's Transmission Capital Expenditure Input Methodology
<b>CAPs</b>	Code Amendment Principles
<b>CBA</b>	Cost Benefit Analysis
<b>CBA</b>	Cost Benefit Analysis
<b>CCGT</b>	Combined Cycle Gas Turbine
<b>Code</b>	Electricity Industry Participation Code
<b>Commission</b>	Electricity Commission
<b>Connection Code</b>	Schedule 8 of the Benchmark Agreement
<b>Discussion Paper</b>	The TPAG's Transmission Pricing Discussion Paper (this paper)
<b>DSM</b>	Demand Side Management
<b>FTR</b>	Financial Transmission Right. A right to receive the price difference for a defined MW for a defined time between points on a transmission network.
<b>GEM</b>	The Authority's Generation Expansion Model. GEM is a long term capacity expansion planning model used for analyses of the New Zealand electricity sector. Further detail on the GEM model is available at: <a href="https://gemmodel.pbworks.com">https://gemmodel.pbworks.com</a>
<b>GIT</b>	Grid Investment Test
<b>GSC</b>	Grid Support Contracts
<b>Guidelines</b>	In accordance with Subpart 4 of Part 12 of the Code the Authority sets Guidelines for the development of the TPM, Transpower develops the TPM in accordance with the Guidelines and the Authority then makes a determination on the TPM.
<b>HAMI</b>	Historical Anytime Maximum Injection
<b>HVDC</b>	High Voltage Direct Current
<b>Issues Paper</b>	An Issues Paper is required under clause 12.81 of the Code.
<b>LNI</b>	Lower North Island
<b>LRMC</b>	Long Run Marginal Cost

<b>LSI</b>	Lower South Island
<b>MEUG</b>	Major Electricity Users' Group
<b>NAaN</b>	North Auckland and Northland AC transmission investments
<b>NI</b>	North Island
<b>NIGUP</b>	North Island Grid Upgrade Plan investments in the upper North Island grid
<b>NPV</b>	Net Present Value
<b>pricing principles</b>	Section IV of part F of the Rules required that the TPM was consistent with the pricing principles set out in rule 2. The pricing principles were carried over into the part 12 of the Code, but were removed under a Code amendment with effect from 1 June 2011.
<b>RCPD</b>	Regional Coincident Peak Demand
<b>rentals</b>	Rentals, also known as loss and constraint excess payments, are the surplus funds that arise in the wholesale electricity market because nodal pricing results in purchasers paying in aggregate more than generators receive. These rentals arise as a result of losses and constraints between nodes.
<b>Review</b>	Transmission Pricing Review
<b>Rules</b>	Electricity Governance Rules 2003
<b>SI</b>	South Island
<b>SOO</b>	Statement of Opportunities
<b>SPD</b>	Scheduling Pricing and Dispatch software
<b>SRC</b>	static reactive compensation
<b>SRMC</b>	Short Run Marginal Cost
<b>Stage 1 Consultation Paper</b>	Electricity Commission "Transmission Pricing Review: High-Level Options", October 2009, available at: <a href="http://www.ea.govt.nz/document/12312/download/our-work/consultations/transmission/tpr/">http://www.ea.govt.nz/document/12312/download/our-work/consultations/transmission/tpr/</a>
<b>Stage 2 Consultation Paper</b>	Electricity Commission "Transmission Pricing Review: Stage 2 Options", July 2010, available at: <a href="http://www.ea.govt.nz/document/9992/download/our-work/consultations/transmission/tpr-stage2options/">http://www.ea.govt.nz/document/9992/download/our-work/consultations/transmission/tpr-stage2options/</a>
<b>TPAG</b>	Transmission Pricing Advisory Group
<b>TPM</b>	Transmission Pricing Methodology. The TPM is schedule 12.4 of the Code.
<b>TPS</b>	Tilted Postage Stamp
<b>TPTG</b>	Transmission Pricing Technical Group



<b>UNI</b>	Upper North Island
<b>USI</b>	Upper South Island