Transmission Pricing Advisory Group

Transmission pricing discussion paper

Version 5: for TPAG review

3 May 2011

Note:
- This version includes sections 1 to 5 and two appendices only

Note: This paper has been prepared for discussion with TPAG. Content should not be interpreted as representing the views or policy of the Electricity Authority or of TPAG.

Executive summary

Overview of progress on sections

	Section	Progress
1 2 3	Introduction Background Summary of earlier stages of the review	These drafts were provided to TPAG meetings 4, 5, 6 and 7. This draft makes some drafting amendments.
4	Analysis framework	**For review, TPAG meeting 7** This section has been redrafted to improve clarity and consistency. Please read.
5	Assessing options for HVDC cost allocation	This section is has substantially restructured to: • thread the arguments for the status quo and MWh more clearly through section 5 • improve consistency throughout the document • apply the efficiency considerations to all options more consistently and transparently
6	Assessing options for connection	This is sent separately.
7	Assessing options for static reactive	This has been reviewed by the sub-committee and is sent separately.
8	Preferred option for TPM including draft guidelines	To be drafted
9	Conclusion	To be drafted
	Appendix C HVDC analysis	This is as circulated for meeting 7.
	Appendix D TPAG Validation of analysis of the benefits of locational price signalling for economic transmission investments	This was previously a section of the main paper.

Glossary of abbreviations and terms

[insert text]	[insert text]

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1 Introduction

1.1 The Transmission Pricing Advisory Group (TPAG)

1.1.1 The Electricity Authority[1] (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 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 TPAG in accordance with the Electricity Industry Act 2010 (Act) and the Authority's Charter about Advisory Groups[2]. The TPAG terms of reference[3] set out the role of TPAG, the scope of the advice sought, and further details of 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 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 TPAG's analysis and proposed recommendations.

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1 The Electricity Authority succeeded the Electricity Commission on 1 November 2010.

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

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

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 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)[4]. 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 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[5].

1.3.3 Table 2 sets out:

a) 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 indicativ*e* dates.

4 Refer clause 12.81 to 12.83 of the Code.

5 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
TPAG process	**Deadline for submissions on TPAG discussion paper**		Mid-July
	TPAG makes 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
	TPM development Authority publishes Guidelines and Process and requests new TPM. Transpower submits a TPM within **90 days** of request, including indicative prices.	12.88,12.89	4 months
	TPM determination Authority: • may decline to consider the TPM • approves or refers back or amends • publishes proposed TPM for consultation • makes determination on TPM • TPM gazetted, becomes a schedule to the Code	12.90 to 12.94	4 -5 months *Note: More time may be needed if the TPM is referred back to Transpower*
(Not a Code-prescribed process)	**Transpower implementation** 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 II 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	**TPM application** 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	**Transpower to provide prices to customers by 31 December of the year preceding the pricing year.**	Clause 41.5 Benchmark Agreement	By 31 December of year preceding pricing yeat

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 substantive development 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 TPAG. Although TPAG will be responsible for considering the submissions, the Authority will receive submissions on 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 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.

Submissions TPAG Chair c/- Electricity Authority PO Box 10041 Wellington 6143	or	Submissions TPAG Chair c/-Electricity Authority Level 7, ASB Bank Tower 2 Hunter Street Wellington

Tel: 0-4-460 8860
Fax: 0-4-460 8879

1.4.4 Submissions should be received by 5.00 pm on [date]. Please note that late submissions are unlikely to be considered.

1.4.5 The Authority, on behalf of 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 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 TPAG on a confidential basis. However, all information provided to 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 has 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 South Island 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 GIT and a deep definition of 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[6]. 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[7]. 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[8] 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 Investment Input Methodology**. The final input methodology determinations for Transpower, lines companies and other relevant sectors were published on 23 December 2010[9]. 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.

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

[7] 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.

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

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

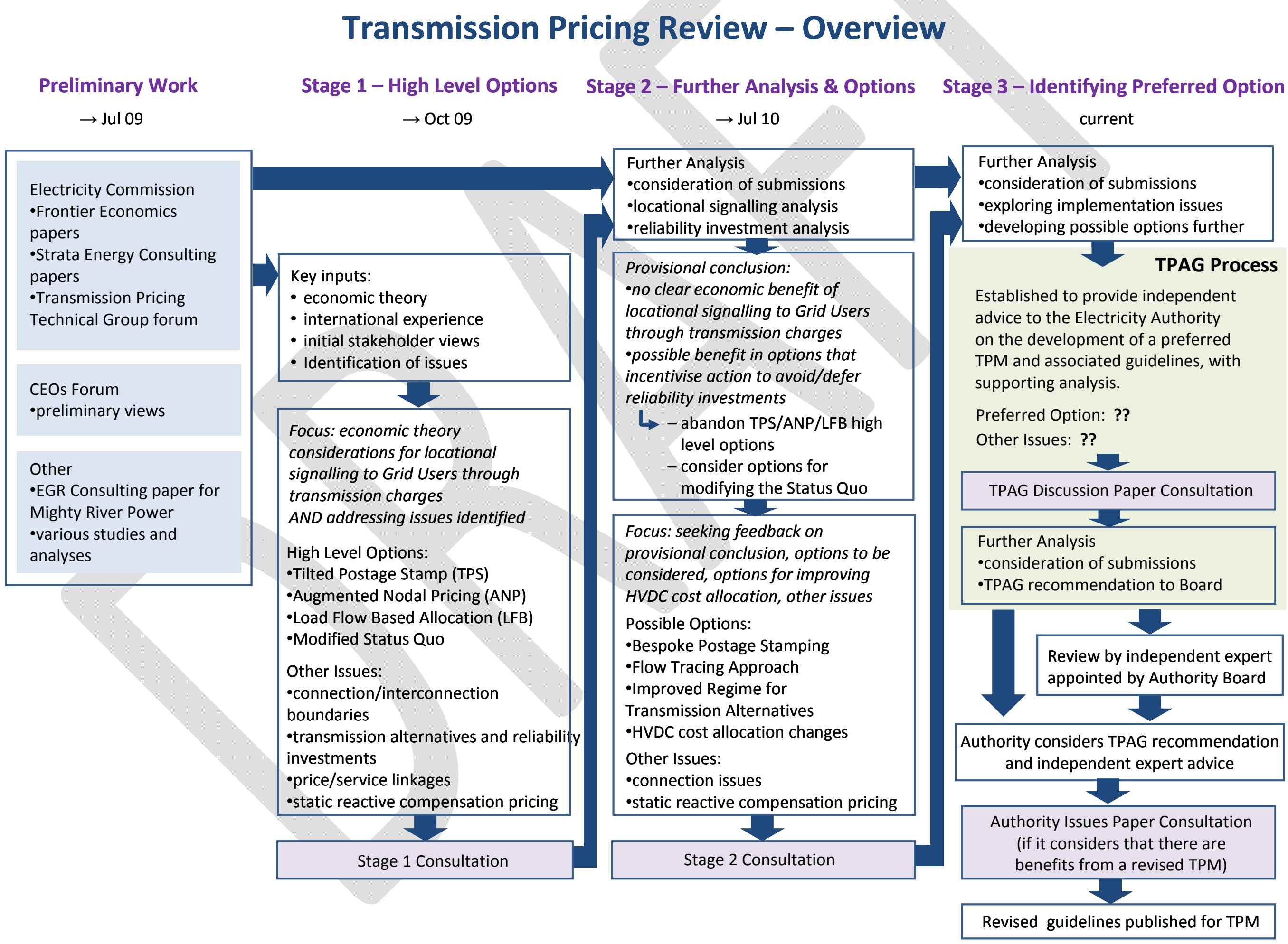
2.4 Overview of the Review to date

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.

Figure 1 Overview of Review – Diagram needs to be updated



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[10].

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.

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[11]. 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"[12].

2.6.4 The high level options included in the Stage 1 Consultation 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** (TILTED POSTAGE STAMP) – 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; and the issue that the value of reliability is not signalled in nodal 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 are made most worse 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

[10] http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

[11] Available at http://www.ea.govt.nz/our-work/consultations/transmission/tpr/.

[12] Also available at: http://www.ea.govt.nz/our-work/consultations/transmission/tpr/.

(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 CEO Forum including analysis from Transpower, and New Zealand Institute of Economic Research (NZIER) reports on behalf of the Major Electricity Users' Group (MEUG) and Rio Tinto. INCLUDE WEBLINKS

a) **CEOs Forum input**: NERA considered that many features of the existing transmission pricing arrangements were fundamentally sound, but there were some potential problems (including issues relating to 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 TILTED POSTAGE STAMP approach), modifying the HVDC charging regime, and some relatively modest amendments to connection charge arrangements.

b) **Transpower work**: Transpower undertook analysis at the request of the CEO Forum working group to determine whether there is an enduring grid characterisation that might support the introduction of a TILTED POSTAGE STAMP pricing methodology and to assess the potential impact of a TILTED POSTAGE STAMP 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'. 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.' 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. 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 Genesis Meridian	Business New Zealand Major Energy Users' Group (MEUG)	Counties Power Northpower Orion	Transpower Electricity Efficiency and Conservation Authority

Mighty River Power (MRP) Todd Energy (late submission)	Norske Skog Pan Pac Rio Tinto Winstone Pulp International	Powerco Vector Electricity Networks Association (ENA)	(EECA)

2.7.2 Views were mixed, and no clear preference emerged from the consultation process. Some submitters supported a TILTED POSTAGE STAMP 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[13].

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[14] 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. TILTED POSTAGE STAMP, 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

[13] Available at: http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

[14] Available at: http://www.ea.govt.nz/our-work/consultations/transmission/tpr-stage2options/.

term, perhaps based on the use of a long run marginal cost (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.

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 RFP 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 South Island generation plant, but with an allocation proportional to generation in MWh rather than based on Historical Anytime Maximum Injection (HAMI);

c) continue to charge South Island generation plant, but with an incentive-free allocation, perhaps based on historical output; and

d) postage stamp – spread costs widely over load and/or generation in both islands.

2.7.8 Finally, the paper addressed the "other issues" from the Stage 1 consultation, 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 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 Genesis Meridian Mighty River Power (MRP) Todd Energy Trustpower	Business New Zealand (MEUG Norske Skog RTANZ	WEL Networks Northpower Powerco Vector Electricity Networks Association (ENA)	Transpower Electricity Efficiency and Conservation Authority (EECA) Opuha Water

2.8.2 Submitters' views on key matters set out in the Stage 2 paper are briefly summarised in Table 5. Appendix [xx] provides a more detailed commentary on key issues raised in submissions and the TPAG's approach to considering these in its work.

Table 5 Brief summary of submissions on Stage 2

Issue	Overall comment
Stage 2 analysis	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. 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. Submitters challenged the analysis of the potential benefits of signalling reliability investments more strongly.
Stage 2 Options	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 tilted postage stamp. 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. 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.
HVDC Options	The consultation paper set out costs and benefits of the existing HVDC charge and four possible options for the allocation of HVDC costs. The three largest South Island generators all favoured postage stamping the HVDC costs. Large user representatives supported further consideration of an alternative option – capacity rights, as an alternative 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. Two submitters considered the existing charging is well-founded and inefficiencies are at worse, negligible, and there is no need to consider the efficiency implications of the charge any further.

Issue	Overall comment
Further Issues	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. Of the three options presented in the consultation paper for the treatment of static reactive compensation, submitters generally favoured either "connection asset definition" or "kvar charging". Transpower presented an alternative variant of kvar charging for consideration. There were strong views against both the status quo and amended status quo which rely on the terms of the Connection Code.

2.8.3 [Note: to be completed, consistent with approved approach to addressing key issues arising in submissions, agreed by TPAG at its meeting of 25 Mar 11]

TPAG's consideration of Stage 2 analysis of value of location-based price signals

2.8.4 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 TPAG. 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, 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.

2.8.5 The basis for reaching this conclusion is set out in Appendix XX.

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.

Scope of the TPAG's work programme

2.8.6 The scope of the TPAG's work programme has been governed by its terms of reference and by the scope of the Stage 1 and 2 analysis.

2.8.7 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.

2.8.8 Following on from stage2 and the conclusion that there does not appear to a demonstrable benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments, the TPAG has not pursued the options of tilted postage stamp, augmented nodal pricing and load flow based allocation.

2.8.9 The TPAG has instead focused on options for HVDC charging, shallower or deeper connection; and static reactive compensation. The decision 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” reflects the TPAG view that there was little benefit in pursuing the specific or bespoke pricing options as the existing RCPD interconnection charges already provide a stronger signal for demand management in regions with growing net demand, and the Commerce Commission regulated “Transmission Alternatives” process already enables generation or demand side options to be commercially contracted for by Transpower where these are efficient.

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[15]"

3.1.4 The Code[16] 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[17].

3.1.5 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[18];

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

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[15] "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".

[16] 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.

[17] There is no current relevant Government Policy Statement.

[18] 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.

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

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[19] and as a result the pricing principles will be 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 anticipates the removal of the pricing principles from the Code as the Authority has made and published its decision. It would be 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 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[20]. These documents are relevant to the Review, and to the TPAG's role. In particular, the assessment 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.

[19] The consultation and decision papers are available at - http://www.ea.govt.nz/our-work/consultations/priority-projects/regulatory-framework-tpm/

[20] 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	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. 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: • 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; • 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 • 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.
Consultation Charter	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: (a) amending the Code; and (b) consulting on proposed amendments to the Code. For the sake of clarity, the Authority has divided the consultation charter into two parts: (a) Part 1 relates to processes for amending the Code; and (b) Part 2 relates to processes for consulting on proposed amendments to the Code. 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.
Charter about Advisory Groups	The Act requires the Authority to establish one or more advisory groups[21] to provide independent advice to the Authority on the development of the Code and on market facilitation. The Act requires the Authority to make, and make publicly available, a charter on: (a) how it will establish and interact with the advisory groups; and (b) when and how it will consult advisory groups on material changes to the Code; and (c) how advisory groups must operate, including provisions concerning procedure.

[21] 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.

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[22], 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 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 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	• Must be consistent with the Act and the Statutory Objective
2.	Clearly Identified Efficiency Gain or Market or Regulatory Failure	• Must be able to demonstrate an efficiency gain or a market or regulatory failure or problem with Code • To be used as a form of screening test
3.	Quantitative Assessment	• Quantitative CBA to assess long-term benefits • Competition and reliability effects are to be assessed within CBA framework • Dynamic efficiency is particularly important • Sensitivity analysis is required

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	• Favour small-scale trials

[22] The TPM is Schedule 12.4 of the Code, any amendments to the TPM will therefore be a Code amendment.

Tie Breaker Principle		Key Points from Code Amendment Principles
	Small-Scale Options	
5.	Preference for Competition	• Prefer options that focus on competition to achieve efficiency gains
6.	Preference for Market solutions	• Prefer options that focus on efficient market-based structures
7.	Preference for Opt-Out Features	• Prefer options that give participants opt-out options • However, non-rivalry and non-excludability conditions will favour "one size fits all" approach
8.	Preference for Non-Prescriptive Options	• Focus on options that specify outputs rather than inputs
9.	Risk reporting	• Final tie-breaker if CBA is inconclusive and principles 5-8 do not discriminate • Report required to assess risks of proceeding or not proceeding with option

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 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[23].

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;

[23] Available at: http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

- the analysis of options for allocating HVDC costs was focussed on efficiency outcomes in the generation market;
- the analysis of options for pricing Static Reactive Compensation 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 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 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 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 the TPAG's approach to assessing transmission pricing options. To recap, the regulatory framework requires that the preferred option 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.

4.1.2 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 The TPAG's Approach to Assessment

4.2.1 The TPAG's approach to assessment 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 TPAG's assessment.

	Interpretation	Application
CAP1	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 CAP2 and CAP3 will test consistency with the statutory objective.
CAP2	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.	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. 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.
CAP3	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.	TPAG has identified options for transmission pricing. The options have been put through a CBA using the efficiency considerations set out below.

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 TPAG has found it helpful to develop a number of more specific efficiency considerations incorporating dynamic, productive and allocative efficiency[24] 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 9 summarises the TPAG 'efficiency considerations' for transmission pricing.

Table 9 Efficiency considerations

Consideration	Implication
1: Beneficiary pays	Apply a beneficiary pays approach: • where beneficiaries can be clearly identified, and benefits outweigh costs; and • 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.
2: Location price signalling	Provide additional or maintain location price signals if these promote more efficient: • coordination of investment and use of transmission, generation, and DSM; or • trade-offs between the costs and benefits of reliability.

[24] 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:

a) 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;

b) 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;

c) Allocative efficiency relates to the efficient use of electricity within the economy.

Consideration	Implication
3: Unintended efficiency impacts	Seek efficiency gains through: • minimising any incentives arising from the TPM that could distort economic dispatch; • minimising any incentives arising from the TPM that create generation, DSM, or transmission investment inefficiencies; • adopting pricing structures that minimise allocative inefficiencies arising from the recovery of fixed and sunk costs; and • avoiding incentives to shift costs between participants without any corresponding efficiency gain (gaming).
4: Competitive neutrality	Provide a level playing field for long term competition in generation and retail.
5: Implementation and operating costs	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.
6: Good regulatory process	Adopt an approach that: • is consistent between regulators; • is durable; • is consistent over time; • is consistent over the whole grid; • is compatible with market arrangements; and • avoids wealth transfers and step changes in prices unless these are justified by efficiency benefits. This may involve providing transition arrangements.

4.3.3 These efficiency considerations are discussed further in the following sections.

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. There are two benefits of a beneficiary pays approach:

a) 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[25];
- 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.

b) Benefits in terms of improved durability of the methodology and improved regulatory certainty, through reduced disputes and interventions, where beneficiaries can be clearly identified.

4.3.5 However, there are several issues to consider in applying a beneficiary-pays approach to allocating the cost of transmission assets:

a) **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 can't hold-out to delay welfare enhancing investments.

b) **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 usage can be subjective and will depend on a range of assumptions.

c) **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.

d) **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

[25] Note that under a postage stamp form of transmission pricing, users would still have a general incentive to participate and provide accurate information. However, this incentive may have little effect if there is a very broad beneficiary pays allocation of costs. It may be significantly improved if a very specific beneficiary (or beneficiary group) can be clearly identified and if there is a clear alignment between decision-rights, cost and benefits.

the ex-ante value to those parties from the investment[26]. 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[27].

e) **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.

Efficiency consideration 2: locational price signalling

4.3.6 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.

4.3.7 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[28]. 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.

4.3.8 The regional structuring of the allocation of interconnection charges Regional Coincident Peak Demand Peak (RCPD) interconnection charges is an attempt to provide additional price peak demand management signals in regions with growing net demand[29] requiring transmission "reliability" investments

4.3.9 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 or static reactive compensation or from maintaining the existing locational price signalling through the TPM.

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26 This tends to happen automatically in a fully commercial environment where investments only proceed if there are sufficient beneficiaries willing to commit to meet the costs of a particular investment.

27 The theoretical ideal would be for beneficiaries to be charged a lump sum (or fixed annuity) for lumpy new investments. In practice this is seldom achievable as a result of difficulties involved in determining individual beneficiary shares through a regulated central planning process rather than through commercial negotiation. Relatively arbitrary usage based allocation methods are sometimes the only practical option.

28 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.

29 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

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

4.3.11 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

4.3.12 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

4.3.13 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

4.3.14 Good regulatory practice should seek regulation that is transparent, easily understood, defendable, 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.

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

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 over time. This enables market participants to more easily predict future regulatory behaviour, and it also minimises the incentives for lobbying. Ideally the approach should be applicable in a situation where significant new investments are being considered and where these investments have just been committed.

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 should be justified by clear efficiency improvements. Any proposed change should be an effective, efficient and proportionate response to the issue concerned. Where change is justified then it should 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.

4.4 The TPAG's Assessment

4.4.1 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.

4.4.2 Using the framework based on the CAPs outlined above 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;
- considered the possible alternative options; and
- assessed the relative costs and benefits of the options.

4.4.3 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.

4.5 Counterfactual and sensitivity analysis

4.5.1 The assessments of the 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);

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.

4.5.2 Where appropriate, the assessment has considered the sensitivity of the results to different scenarios:

a) Alternative future electricity sector developments.

b) The introduction of a financial transmission right (FTR) between North and South Island nodes, with the holders of any FTR receiving the loss and constraint excess between the nodes, and the proceeds from the FTR auction allocated under different scenarios.

c) The introduction of scarcity pricing mechanisms.

5 Assessing options for HVDC cost allocation

5.1 Introduction

5.1.1 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.

5.1.2 This section:

- considers whether under the current arrangements for HVDC cost allocation, there is a possible market or regulatory failure or efficiency gain sufficient to justify the consideration of other approaches;
- considers the possible alternative options; and
- assesses the relative costs and benefits of the options by applying the efficiency considerations set out in section 4 and using the status quo as a counterfactual.

5.1.3 Analysis supporting this section is contained in Appendix C.

5.2 Issues with the current HVDC cost allocation – Possible market or regulatory failure, potential for efficiency gains?

5.2.1 Under the current TPM, the HVDC costs are charged to all SI generators with an allocation proportional to peak (kW) generation based on Historical Anytime Maximum Injection (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 my be lower than this depending on how rentals relating to the HVDC assets are allocated.

5.2.2 The current arrangements create a number of possible issues relating to:

a) competition effects that may lead to inefficiencies in generation investment;

b) investment and dispatch inefficiencies resulting from the HAMI price structure; and

c) on-going durability issues.

Competition effects that may lead to inefficiencies in generation investment

5.2.3 The current HVDC charges on SI generators pose two possible competition issues. First, because these charges will not be faced by new entrant generators in the North Island, SI new entry is disadvantaged relative to NI new entry. And second, in the South Island the allocation mechanism may favour new generation investment by large incumbent SI generators, relative to small incumbent generators or new entrants. There is also a possible competition issue with the HAMI allocation method in that it favours base load relative to peaking and low capacity factor generation technologies. This is discussed in 5.2.17 below.

5.2.4 The first competition issue may lead to potential generation investment inefficiency because new SI generators face an additional cost which does not reflect any marginal costs in the period until a new HVDC investment is required. The HVDC charge adds around 10% to the total cost of a new project, and is likely to cause SI generation options to be delayed relative to otherwise equivalent NI options.

5.2.5 The second competition issue may lead to large incumbent SI generators increasing their dominance in the SI with consequential impacts on competition in generation and retail.

Possible generation investment inefficiency from delaying SI generation

5.2.6 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 of new generation investments and an associated economic loss.

5.2.7 Appendix C describes an analysis of the possible increase in the present value of future new generation investments using the following methodology:

- A merit order of new generation 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.

5.2.8 Table 10 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[30], new investment costs, fuel costs, exchange rates and other factors. For this reason sensitivity to these factors was tested and is reported in Appendix C.

5.2.9 Table 10 suggests that the generation investment inefficiency associated with the current HVDC charge could be between $14m and $51m (average $31m) if SI generators continue to receive HVDC rentals, or between $19m and $64m (average $38m) 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 and, arguably, should be avoided if there are no compelling reasons to retain the existing pricing structure and the cost of changing the pricing is low.

5.2.10 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 of likelihood of the inefficiency for example: generation investors' strategies, physical hedging positions, capital constraints and the likelihood of projects gaining resource constraints.

Table 10 Generation Investment Inefficiency of HVDC charge (HAMI allocation)

HVDC Rentals	Net HVDC Opportunity Cost	Economic cost (NPV $m)
SI generators continue to get HVDC rentals	$35/kW/yr	$14-51m (average $31m)

30 SI generators may not continue to receive the HVDC rentals if the location hedging proposal goes ahead, hence sensitivity without HVDC rentals is included.

HVDC Rentals	Net HVDC Opportunity Cost	Economic cost (NPV $m)
SI generators don't get HVDC rentals	$40/kW/yr	$19-64m (average $38m)

Potential impact on competition between incumbents in the SI

5.2.11 The current allocation of HVDC costs may favour new generation investment by large incumbent SI generators, relative to small incumbent 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. A completely independent new SI generator will see the full HVDC cost for its new generation, but all incumbents will benefit from a reduction in their share of the costs.

5.2.12 It can be shown that the HVDC opportunity cost for an incumbent SI generation company is 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[31].

5.2.13 The potential counterfactuals and the impact on the largest incumbent's (Meridian with a 70% share of HVDC charges) opportunity cost are described in Appendix C and are summarised in Table 11. This shows that Meridian can have a significant artificial competitive advantage over smaller competitors and new entrants in 2 of the 3 possible counterfactuals.

Table 11 SI generation investment counterfactuals

Option	Description	Meridian's net HVDC opportunity cost
Counterfactual 1	Meridian assumes that if it invests in the SI it will displace a competitor investment in the SI	$35/kW/yr
Counterfactual 3	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
Counterfactual 2	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 the analysis in this paper it has been assumed that the cost impact is half way between the two extremes.	$23/kW/yr

5.2.14 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

[31] 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.

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.

5.2.15 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 are conservatively based on the results for counterfactual 1 which does not give Meridian an artificial competitive advantage[32].

5.2.16 In submissions Todd also 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 within distribution networks, at the possible cost of lost economies of scale and increased distribution losses. This is considered to be a second order potential issue and has not been quantified.

Generation investment and dispatch inefficiencies from the HAMI price structure

5.2.17 In addition to the potential competition issues there are specific issues arising from the HAMI allocation methodology. This methodology provides incentives to:

a) withhold offers of short-term generating capacity in the SI;

b) mothball or retire existing peaking capacity in the SI;

c) discourage investment upgrading existing generation to provide additional peaking capacity in the SI; and

d) bias new SI generation towards energy rather than peak capacity (for example in the design of new wind and hydro schemes).

5.2.18 Some generators report that they are withholding over 100MW of peaking capacity in the SI as a result of the incentives arising from the HAMI allocation[33]. This capacity is available for grid emergencies as Transpower has agreed not to adjust generators' HAMI in these situations, but it is not made available at other times.

5.2.19 This withholding of capacity can lead to dispatch inefficiencies which the Electricity Commission estimated to be towards the lower end of a $0-100m range[34]. It is likely that withheld capacity would be returned to the market once the value of SI peaking increases; hence this dispatch inefficiency may be more likely to be in the range $0-$10m NPV.

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[32] It is shown in Appendix C 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.

[33] See page 28 of the Stage 2 Consultation Paper

[34] 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 lead to the construction of 100MW of unnecessary NI peaking capacity. The lower bound of zero was based on their assessment that there should be 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.

5.2.20 In addition to the dispatch inefficiency there is potential generation investment inefficiency from discouraging new peaking capacity in the South Island which the Electricity Commission estimated to have an economic cost in the range $0-25m NPV[35].

On-going durability issues

5.2.21 The existing HVDC charges have been repeatedly challenged. Some submitters to the Stage 2 Consultation Paper pointed out that there is a potential inconsistency in allocating all HVDC charges to SI generators when they are just one of several beneficiaries and that the HVDC seems to be treated differently from other interconnection assets within each island where beneficiaries are more readily and robustly identified. These views have been disputed by others, but are indicative of an ongoing debate which is leading to regulatory uncertainty.

Conclusion

5.2.22 [This section has raised possible issues with the status quo HVDC cost allocation:

- there is a disincentive for new generation in the SI relative to NI which may lead to generation investment inefficiencies. The analysis estimates a possible generation investment inefficiency of between $14m and $51m NPV;
- there is a possible risk that there is a lack of competitive neutrality between large SI incumbents and new SI entrants;
- the HAMI allocation may discourage investment in new peaking capacity in the SI. The analysis estimates a possible generation investment inefficiency relating to investment in peaking plant of up to $25m NPV;
- there is a possible inefficiency in the dispatch of SI generation of up to $10m NPV; and
- there have been and are likely to continue to be challenges to the current mechanism.

5.2.23 To be consistent with the statutory objective the TPM must promote efficiency, competition and reliability. Changes to the status quo should be contemplated if there is a demonstrable market or regulatory failures or potential efficiency gains available. TPAG concludes that there is sufficient evidence of possible market and regulatory failures and potential efficiency gains to warrant analysis of alternative TPM options.]

5.3 The Options

5.3.1 The stage 2 consultation paper suggested that there may be material benefits in alternative HVDC charging regimes. It proposed three possible alternatives to the status quo and considered a further Capacity Rights option (proposed by NZIER). These options are summarised in Table 12 along with a further transitional option developed by TPAG.

[35] See section 4 of Appendix 4 to the Stage 2 review. This is based on the assumption that there is 200MW of SI incremental peaking capacity that would be economic without the HAMI cost structure, but would not be with the HAMI charges and would be replaced by 200MW of NI peaking capacity. This assessment is a likely to be a lower bound on the actual cost as it was based on lower HVDC HAMI charges of $30/kW and on counterfactual 3. However the uncertainties in the calculation are such to justify the lower bound being used in this updated analysis.

Table 12 HVDC Stage 2 Options

Option	Description	Rationale for Change
Status Quo	HVDC costs are met through a charge on South Island generation plant with charges based on Historical Anytime Maximum Injection (HAMI).	
HVDC Capacity Rights	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 the HVDC link.
MWh allocation	HVDC charge would remain on South Island generators but would be allocated proportionately to generation in MWh rather than 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 and thereby discouraging investment in peak generation or generators operating to their peak capacity.
'Incentive-free' allocation to SI generators	HVDC charge would remain on existing South Island 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.
Postage Stamp	HVDC costs would be spread broadly throughout New Zealand over load, in the same manner as interconnection assets are charged currently.	The objective would be to avoid possible distortion to competition in the new generation market.
Postage Stamp Transition	As for postage stamp, but incorporating a transitional "incentive free" allocation to SI generators.	As for postage stamp, while removing large step changes in prices and wealth transfers

Variants of the HVDC capacity rights options

5.3.2 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[36] 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 13.

[36] See "A capacity Rights Regime for the HVDC Link", NZIER Report to Rio Tinto Alcan New Zealand Ltd, 22 March 2010.

Table 13 Capacity Rights Options

	NZIER Proposal	Merchant Link Proposal
Overseas model	None that TPAG is aware of.	Australian market interconnector regime[37].
Concept	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.
Initial Allocation	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.
Secondary Trading	Requires half hour secondary trading up to gate closure and a separate spot auction of rights alongside SPD.	Additional secondary trading may occur if there is a demand, but is not required.
Market clearing and Settlement	Requires a 2 solve process[38] to identify "users"[39] 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

5.3.3 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.

5.3.4 These alternative MWh allocation methodologies have not been included as separate options as they would have a similar effect to the full MWh allocation to SI generators. It would be desirable to consider these if the MWh allocation approach is a preferred option.

[37] 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.

[38] 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.

[39] 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

Variants of the Postage Stamp Options

5.3.5 The potential generation investment inefficiency can be avoided if new SI generation is not required to pay HVDC charges through postage stamping. 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 of these alternatives are expected to be similar, so they have not been treated as separate options for the purpose of this analysis. These alternative implementations could be explored further if postage stamping is a preferred option.

Transition to Postage Stamping the HVDC charge

5.3.6 Under a transition to postage stamping approach existing 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 SI generators over the transitional period 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.

5.3.7 The allocation of costs to existing SI generators 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 acceptable. In addition the transitional arrangements can also accommodate the value impact of removing the right to 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.

5.3.8 There are a range of different transition options, with different levels of allocation of HVDC costs and different transition durations and phasing. These are discussed in more detail provided in [section xx- currently in the note to TPAG on transition options].

5.4 Assessment of Options against Efficiency Considerations

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

Efficiency consideration 1: Beneficiary pays

5.4.2 This section:

a) considers the possible benefits from applying a beneficiary pays principle to the allocation of HVDC costs (investment efficiencies and durability through reduced disputes);

b) considers possible ways to identify the beneficiaries, and

c) assesses the extent that the options apply a beneficiary-pays principle compared with the status quo.

Possible benefits from applying a beneficiary pays principle to the HVDC costs

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

a) investment efficiency benefits through improved investment decision making; and

b) benefits in terms of improved durability of the methodology and improved regulatory certainty.

5.4.4 In the case of the HVDC, TPAG notes that the pole 3 upgrade is now committed and hence any investment efficiency benefits from applying a beneficiary pays approach must now relate to any further HVDC investments such as HVDC upgrade investments which are possibly 20-30 years in the future or the possible investment in a second cable for pole 3.

5.4.5 There may be potential efficiency gains from applying a beneficiary pays principle if, for example:

a) Transpower has a tendency to propose too early or excessively large/costly[40] new HVDC grid investment in the future; and

b) this tendency is not restrained by the Commerce Commission's application of the grid investment test, or by the introduction of alternative incentive based regulation[41] or by other mechanisms[42] ; and

c) The allocation of the HVDC costs to beneficiaries results in more efficient timing or size of new HVDC investments.

5.4.6 For example, better information from beneficiaries may result in:

a) avoiding a $350m HVDC investment being built 5 years too early in 25 years time – worth around $16m NPV.

b) Avoiding a 30% over-investment a $450m HVDC investment in 25 years – worth around $15m NPV.

c) deferring investment in a second $180m cable and filters etc[43] for Pole 3 by 5 years from 2016 - worth around $39m NPV.

5.4.7 Conversely, if beneficiaries are not charged they may be incentivised to lobby for a new or expanded HVDC link whether it is needed or not.

5.4.8 In summary, the investment efficiency benefits in applying the beneficiary pays principle to the allocation of HVDC costs may be of the order of $0m to $39m, if the beneficiary pays principle is applied in a manner that incentivises participants appropriately and consequently improves the decision making process.

5.4.9 The benefits from reduced disputes are less quantifiable, but if beneficiaries can be robustly and objectively identified in a way that is cost-effective, there could be reduced disputes or interventions leading to a more durable allocation of HVDC costs.

40 Note that this would have to exceed the level economically justified by the asymmetry of consequences, option value, or maximization of economies of scale etc.

41 This is currently being considered.

42 Such as a requirement for Transpower to move to a more market driven commercial approach to new HVDC grid investments possibly involving the auctioning of FTRs or capacity rights on new capacity should such options be proven to be workable within the next 20 years or so.

43 See TransPower's 2011 Annual Planning Report, page 92. This indicates they are planning to submit a proposal to extend the capacity of the HVDC to 1400MW by adding an additional cable and filters. This indicates an estimated cost band E = $50-$100m, but past experience indicates that the approved cost might be considerably higher. The $180m used in this illustrative calculation is based on a 2007 estimate of $123m with allowance for inflation and an additional cost overrun.

Identifying beneficiaries of the HVDC link

5.4.10 Under current arrangements the HVDC costs are allocated to SI generators. The AC interconnection costs are allocated to distributors (load). The Commission, in the explanatory paper for its final decision on HVDC pricing methodology (March 2006) considered that beneficiaries of the HVDC were widespread but not all beneficiaries would face strong incentives (or be able to) to identify least cost investment options if they were paying for new and replacement investments in the HVDC link.

5.4.11 There are differing views within TPAG and other participants on whether SI beneficiaries are the main beneficiaries.

5.4.12 TPAG has considered what might be involved in identifying the beneficiaries of the HVDC. It considered this from two perspectives: using a centrally-determined beneficiary assessment approach; and using HVDC capacity rights as a market-based approach to identifying beneficiaries.

Using a centrally-determined approach to determining beneficiaries

5.4.13 A beneficiary assessment was not applied when pole 3 was approved[44] however TPAG has discussed what would have been involved in such an assessment and the likely implications. In 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 with pole 3 replacing pole 1, relative to the case where pole 1 was retired.

5.4.14 The HVDC link provides a mix of benefits that varies according to time frame and circumstance. For example it primarily benefits[45]:

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.

5.4.15 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).

5.4.16 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

[44] It is recognized 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.

[45] 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 as discussed later in 5.4.18.

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, then the HVDC link can allow a balanced joint development of renewables taking advantage of diversity in both investment costs and operation (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 either 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.

5.4.17 Apportioning benefits between these 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.

5.4.18 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.

5.4.19 These considerations indicate that beneficiaries are likely to change over time and objective identification of specific beneficiaries of the pole 3 upgrade is difficult and problematic. Identifying the beneficiaries of other interconnection assets could be less problematic than for the HVDC.

HVDC capacity rights as means to identify beneficiaries

5.4.20 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, identification of beneficiaries was possible. The capacity rights approach initially suggested by NZIER could potentially achieve this. The potential costs and benefits of this approach are explored here.

5.4.21 Table 13 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). This approach does not require "users" or "beneficiaries" of the HVDC to be identified each trading period.

5.4.22 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 issues for Transpower, hedging, system security and market power.

5.4.23 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. They suggest that this should provide a more stable identification of beneficiaries and lead to less dispute and uncertainty about who should be funding the costs associated with the HVDC link.

Assessment of the options relative to the status quo

5.4.24 If a beneficiary pays principle is applied in a cost-effective, clear and objective manner, it should lead to investment efficiency benefits for future HVDC investments and potentially mean fewer disputes and greater regulatory certainty

5.4.25 The status quo applies the costs to the SI generators only. Whilst TPAG members agree that the SI generators are one of the beneficiaries, there are varying views on whether other beneficiaries should be charged and whether the allocation to the SI generators will lead to investment efficiency gains through participation in investment decision making. Although the SI generators are incentivised to take part in the investment decision making process, they may not be incentivised to seek the most efficient solution for the long term benefit of consumers.

5.4.26 The allocation to the SI generators has proved contentious and is likely to continue to be so leading to on-going durability issues.

5.4.27 Table 14 below assesses both whether the options apply a beneficiary pays approach and how it compares with the status quo.

Table 14 Application of efficiency consideration 1: beneficiary pays to HVDC options

Option	Application of the beneficiary pays principles. Assessment relative to status quo
HVDC capacity rights	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'. Capacity rights should more clearly and objectively identify beneficiaries compared to the status quo resulting in reduced likelihood of disputes.
MWh allocation	The MWH allocation retains the charge on SI generators. Its application of the beneficiary pays principles is the same as the status quo. SI generators remain incentivised to be involved in the investment planning process but durability may be a problem.

Option	Application of the beneficiary pays principles. Assessment relative to status quo
Incentive-free allocation to SI generators	The incentive-free allocation to SI generators retains the charge on existing SI generators, but removes it from new generators. Its application of the beneficiary pays principles is similar to that of the status quo but may lead to increased disputes and uncertainty if new generators are not charged. SI generators remain incentivised to be involved in the investment planning process.
Postage stamp	The postage stamp option spreads the cost of the HVDC assets over load, and although loads are beneficiaries of the HVDC, this is unlikely to lead to incentives on load to participate in the decision making process. Postage stamping of HVDC charges is a weak application of the beneficiary pays principle and may reduce participation in the investment planning process. The prospect of disputes is the same as for the status quo.
Postage stamp transition	The application of the beneficiary pays principle for this option is similar to the postage stamp option.

Efficiency consideration 2: Locational price signalling

5.4.28 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.

5.4.29 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 if it is costly or difficult to implement.

5.4.30 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.

5.4.31 The analysis of the impact of the locational signal of the current cost allocation is set out in section 5.2 and estimates that the signal gives rise to possible generation investment inefficiencies of between $14m and $51m NPV over the next 30 years.

5.4.32 The MWh allocation to SI generators maintains the 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.

5.4.33 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 the whether the costs in terms of generation investment inefficiencies can be offset by the benefits of locational price signalling.

Table 15 Application of efficiency consideration 2: locational price signalling to HVDC options

	Assessment relative to status quo
HVDC capacity rights	Involves a locational signal which could be more refined that the existing signal, but the impact of the locational signal has not been assessed by TPAG.
MWh allocation	Maintains the status quo locational signal to SI generation, but shifts the signal away from lower capacity factor towards base load technologies.
Incentive-free allocation to SI generators	No locational signal (removes the locational signal provided by the status quo).
Postage stamp	No locational signal (removes the locational signal provided by the status quo).
Postage stamp transition	No locational signal (removes the locational signal provided by the status quo).

Efficiency consideration 3: Unintended efficiency impacts

5.4.34 The transmission pricing methodologies have the potential to involve unintended efficiency impacts. The unintended efficiency impacts relevant to the HVDC are:

a) Generation investment efficiency impacts

b) Peaker investment efficiency impacts

c) Dispatch efficiency impacts

d) Allocative efficiency impacts

5.4.35 The table below assesses the unintended efficiency impacts for the HVDC options relative to the status quo.

Table 16 Application of efficiency consideration 3: unintended efficiency impacts

	Assessment relative to status quo
HVDC capacity rights	**Generation investment, peaker investment and allocative efficiency** – An analysis of the unintended efficiency impacts for would be complex and 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. **Dispatch efficiency** – TPAG has not analysed dispatch efficiency under a capacity rights option but considers that efficiency would be reduced relative to the status quo.
MWh allocation	**Generation investment** – Would reduce the possible generation investment inefficiency from the disincentive to invest in SI generation (+$10m to $12m) **Peaker investment** – would avoid penalising peak injections so avoid discouraging investment in peak generation (+0 to $25m) **Dispatch efficiency** – 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[46] 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. **Allocative efficiency – no change from the status quo**
Incentive-free allocation to SI generators	**Generation investment** – would eliminate the possible generation investment inefficiency by recovering costs from SI generators using an 'incentive free' allocation, although it might introduce other incentives on existing SI to avoid costs depending on the design of the allocation. (+14m to $51m) **Peaker investment** – would eliminate the possible peak investment inefficiency of the status quo (+0 to $25m) **Dispatch efficiency** – would eliminate the possible dispatch inefficiencies of the status quo (+$0 to $10m) **Allocative efficiency** – no allocative efficiency effects
Postage stamp	**Generation investment** – would eliminate the possible generation investment inefficiency by recovering costs load (+14m to $51m) **Peaker investment** – would eliminate the possible peak investment inefficiency of the status quo (+0 to $25m) **Dispatch efficiency** – would eliminate the possible dispatch inefficiencies of the status quo (+$0 to $10m) **Allocative efficiency**– - $1m to $2m

46 See section 5 of Appendix 4 to the Electricity Commission's Transmission Pricing Review: Stage 2 Options, July 2010.

	Assessment relative to status quo
Postage stamp transition	**Generation investment** – would eliminate the possible generation investment inefficiency by recovering costs load (+14m to $51m) **Peaker investment** – would eliminate the possible peak investment inefficiency of the status quo (+0 to $25m) **Dispatch efficiency** – would eliminate the possible dispatch inefficiencies of the status quo (+$0 to $10m) **Allocative efficiency** – - $0.1m to $1m

5.4.36 Section 5.2 has discussed the first three of these with respect to the status quo HVDC cost allocations and Appendix C has described the analysis in more detail.

Generation investment efficiency analysis for MWh allocation

5.4.37 The investment inefficiency analysis with respect to the status quo has been repeated using a MWh allocation to SI generators[47] and is also set out in Appendix C. The results are summarised in Table 17 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 17 Generation Investment Inefficiency of HAMI and MWh HVDC charges

HVDC Rental allocation	HVDC cost allocation and net Opportunity 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)

5.4.38 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 South Island generators but was allocated proportionately to generation in MWh rather than HAMI.

5.4.39 Although an 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 receive HVDC rentals and between $10m and $36m (average$26m) if they don't.

Allocative efficiency

5.4.40 If the HVDC costs were allocated to off-take customers in the same manner as the existing interconnection charges (which would have involve low implementation and on-going costs) then

[47] 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.

Regional Coincident Peak Demand (RCPD) transmission prices to those customers would increase by $24/kW, customers would receive HVDC rentals (or potentially FTR residuals) and customers would likely see an average increase in delivered energy prices of approximately $3/MWh[48]. Other forms of postage stamping (such as recovery 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[49].

5.4.41 This price increase 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 LRMC. The timing and uncertainty in the reduction in the LRMC is assessed in Appendix C. The possible net effect over time is illustrated in **Error! Reference source not found.**[50]

5.4.42 If prices were to rise by $3/MWh without any countervailing drop in wholesale prices there could be an allocative deadweight loss[51], associated with the price increase, estimated as $0.3m/yr[52] or $2.5m net present value. However, it is more likely that there would 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 SI generators continue to pay a portion and a price increase to customers is avoided, this deadweight loss would be reduced further.

48 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.

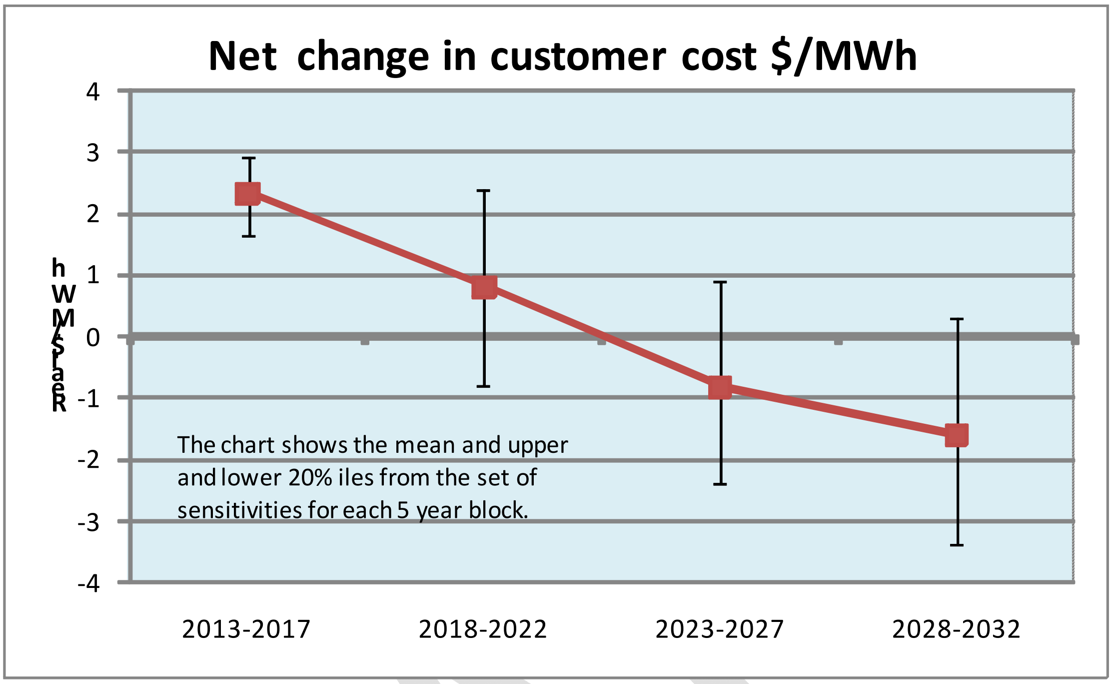
49 If HVDC charges are allocated to all generators on a MWh basis then this is likely to flow directly through into higher wholesale prices as it would be a common increase in the short run and long run marginal cost of all generation. Similarly a 50:50 split between generators and customers would result in similar total $3/MWh increase, half coming from higher wholesale prices and half from higher interconnection prices.

50 This chart has been developed on the assumption that reductions in the LRMC curve will flow through into average NZ wholesale prices over time. It is recognized that the exact timing and distribution between islands will vary according to supply and demand and competitive market dynamics.

51 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.

52 $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*220/2 = $340,000/yr.

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



5.4.43 This potential deadweight loss may also be offset if there are efficiency gains from higher RCPD charges deferring transmission reliability investments[53].

Efficiency consideration 4: Competitive neutrality

5.4.44 There are a number of risks and issues relating to competitive neutrality for the allocation of HVDC costs. Competitive neutrality issues potentially occur

a) between NI and SI generation

b) between large incumbent and other SI generators

c) between different technologies

5.4.45 The benefits of these three competitive neutrality issues have also been included in the assessment of unintended efficiency impacts above.

5.4.46 There is also an emerging competition issue if the 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.

5.4.47 The table below assesses the competitive neutrality of the HVDC options relative to the status quo.

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[53] 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.

Table 18 Application of efficiency consideration 4: competitive neutrality

	Assessment relative to status quo
HVDC capacity rights	Facilitates market-based commercial grid investment. Introduces potential market power issues arising from rights to restrict HVDC capacity.
MWh allocation	Would reduce the competitive detriment to new SI generation
Incentive-free allocation to SI generators	Would provide a level playing field for competition in new generation between the SI and NI, and between incumbent and other generators within the SI.
Postage stamp	Would provide a level playing field for competition in new generation between the SI and NI, and between incumbent and other generators within the SI. Eliminates the competitive issue arising from the FTR proposal.
Postage stamp transition	Would provide a level playing field for competition in new generation between the SI and NI, and between incumbent and other generators within the SI. Eliminates the competitive issue arising from the FTR proposal.

Efficiency consideration 5: Implementation and operating costs

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

Table 19 Application of efficiency consideration 5 implementation and operating costs to HVDC options

	Assessment relative to status quo
HVDC capacity rights	Involve significant changes to the market clearing software (SPD) and settlements systems and potentially require the development of associated auctions, 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 SPD are likely to cost 10s of millions and the development of secondary markets could cost of the order of $20 to $40m NPV if the proposed FTR markets is taken as a guide.
MWh allocation	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.
Incentive-free allocation to SI generators	It is unlikely that this option could be implemented in a way that did not lead to immediate disputes unless used as a transition arrangement.

	Assessment relative to status quo
Postage stamp	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.
Postage stamp transition	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

5.4.49 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 and briefly considers whether there are differences between DC and AC assets that are pertinent to transmission pricing as this relevant when considering the need for consistency over all assets . The table at the conclusion of the section addresses all identified elements of good regulatory practice.

Wealth transfers and step changes in prices

5.4.50 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 is justified it should be well signalled in advance and a transition should be provided so participants have time to adjust.

5.4.51 The TPAG expects there would be small wealth transfers between generators from a change to a MWH allocation, but there would be more substantial wealth transfers 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 TPAG.

5.4.52 If the HVDC costs were allocated to off-take customers in the same manner as the existing interconnection charges (which would have involve low implementation and on-going costs) then Regional Coincident Peak Demand (RCPD) transmission prices to those customers would increase by $24/kW, customers would receive HVDC rentals (or potentially FTR residuals) and customers would likely see an average increase in delivered energy prices of approximately $3/MWh[54]. Other forms of postage stamping (such as recovery 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[55].

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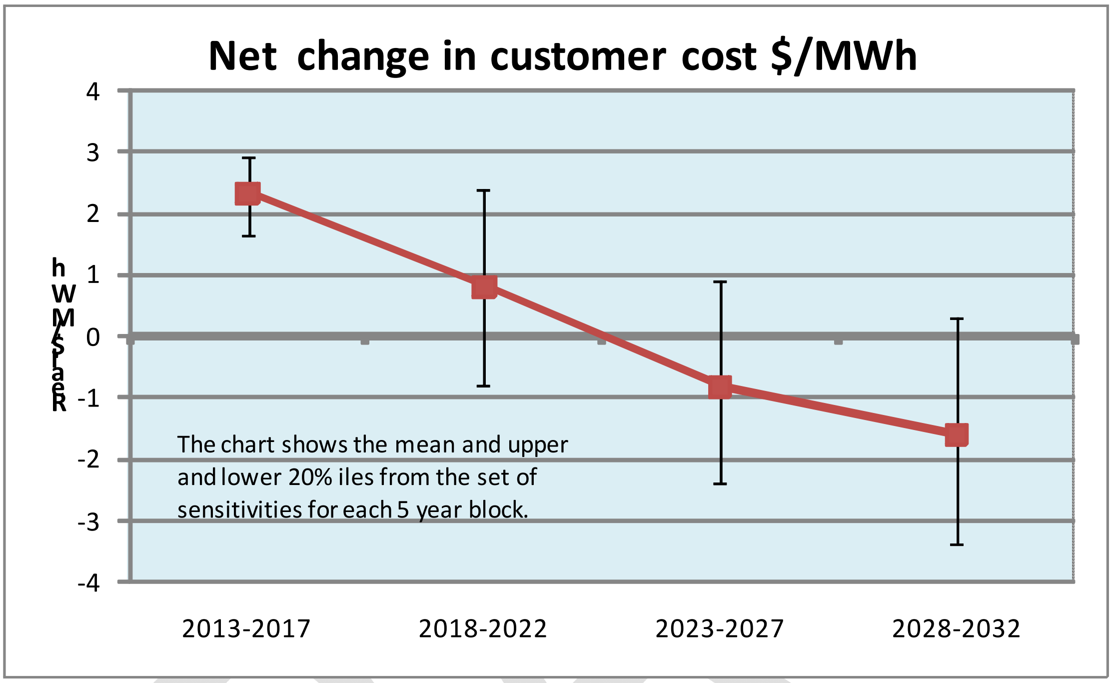
[54] This is estimated on the basis of $147m real HVDC revenue requirement in 2013/14 minus $14m expected HVDC rentals over total NZ off take demand of approximately 42,000GWh.

[55] If HVDC charges are allocated to all generators on a MWh basis then this is likely to flow directly through into higher wholesale prices as it would be a common increase in the short run and long run marginal cost of all generation. 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.

5.4.53 This price increase 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 LRMC. The timing and uncertainty in the reduction in the LRMC is assessed in Appendix C. The possible net effect over time is illustrated in **Error! Reference source not found.**[56].

Figure 3 Possible impact of a move to postage stamping HVDC charges



5.4.54 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, but they are likely to be as follows:

- SI generators: lower transmission costs offset by lower medium term wholesale prices – could be net positive or negative in medium term;
- NI generators: lower medium term wholesale prices – likely to be 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 be 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)– likely to be net zero or negative.

[56] This chart has been developed on the assumption that reductions in the LRMC curve will flow through into average NZ wholesale prices over time. It is recognized that the exact timing and distribution between islands will vary according to supply and demand and competitive market dynamics.

5.4.55 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 effects.

5.4.56 Although value transfers associated with a change in pricing are not directly included in measures of allocative inefficiency, they can indirectly give rise to economic costs in the regulatory process.

5.4.57 The application of good regulatory practice suggests that 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 need to be seen in the context of other changes in the market. For example increasing transmission charges arising from the major AC grid investments are likely to be of the order of $4/MWh.

5.4.58 It is debateable 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. It may be better to find an alternative option which eliminates the residual inefficiencies and minimises the value impacts.

5.4.59 A transitional approach to postage stamping HVDC charges which retains the historical allocation of HVDC costs to SI generator 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 efficiencies to be gained through wholesale price effects would be achieved.

5.4.60 Further details on the postage stamp transition option are given in the note to TPAG on postage stamp transition options.

Whether there are differences between the DC and AC assets that are relevant to transmission pricing

5.4.61 TPAG has considered that, although the HVDC is DC rather than AC it is not significantly different to the interconnection between the 17 other regions in the NZ grid. Flows on the DC and other AC assets are effectively controlled by SPD software scheduling generation offers to meet demand while accounting for the constraints and losses on all transmission links. This implies that the pricing approach for DC assets should be generally consistent with the approach for AC interconnection assets. This does not mean the costs of the DC assets cannot be allocated in a manner differently from the AC assets if there is and efficiency justification to do so. (For example beneficiaries can be cost-effectively and clearly identified.)

Table 20 Application of efficiency consideration 6 good regulatory practice to HVDC options

	Assessment relative to status quo
HVDC capacity rights	**Consistency between regulators** - Would not be inconsistent with Commerce Commission decision making. **Durability** – 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 37) 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. **Consistency over time** - 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. **Consistency over the whole grid** – 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. **Wealth transfers and step changes in prices** – Possible wealth transfers and step changes in prices are unknown. **Market fit** – 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.

	Assessment relative to status quo
MWh allocation	**Consistency between regulators** – Would not be inconsistent with Commerce Commission decision making. **Durability** – 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 principle 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. **Consistency over time** – Would be consistent over time provided was not subject to ongoing review. What is the likelihood of fluctuations in price? **Consistency over the whole grid** – Would be inconsistent with the approach to charging across the whole grid. **Wealth transfers and step changes in prices** – May involve a small wealth transfer between generators but there would be no step changes in prices. **Market fit** – Similar to the status quo in that retains distinction between DC and AC assets.
Incentive-free allocation to SI generators	**Consistency between regulators** – Would not be inconsistent with Commerce Commission decision making. **Durability** – Likely to be disputed immediately as an arbitrary allocation of costs to a group of participants. **Consistency over time** – Involves a significant change from the status quo creating an inconsistency over time. However, once implemented would be consistent going forward. **Consistency over the whole grid** – This charging methodology would be applied only to the HVDC assets and would not be consistent with the allocation of other costs. **Wealth transfers and step changes in prices** – There would be no wealth transfers and step changes in prices (as for the status quo) **Market fit** – Similar to the status quo.

	Assessment relative to status quo
Postage stamp	**Consistency between regulators -** Would not be inconsistent with Commerce Commission decision making. **Durability** – 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. **Consistency over time** – Involves a significant change from the status quo creating an inconsistency over time. However, once implemented would be consistent going forward. **Consistency over the whole grid** – Is more consistent than status quo as it treats DC and AC interconnection assets in the same manner. **Wealth transfers and step changes in prices** – Value shift in transition is inconsistent with good regulatory practice. **Market fit** – Similar to the status quo but slightly better to the extent it treats AC and DC assets consistently.
Postage stamp transition	**Consistency between regulators -** Would not be inconsistent with Commerce Commission decision making. **Durability** – 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. **Consistency over time** – Involves a change from the status quo creating an inconsistency over time. **Consistency over the whole grid** - Is more consistent than status quo as it treats DC and AC interconnection assets in the same manner. **Wealth transfers and step changes in prices** – 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 price shocks. **Market fit –** Similar to the status quo but slightly better to the extent it treats AC and DC assets consistently.

5.5 Assessment summary

5.5.1 This summary provides:

a) a comparison of the pros and cons of the options; and

b) a summary of the assessment of the options relative to the status quo.

5.5.2 **Error! Reference source not found.** Table 21 summarises the TPAG assessment of the advantages and disadvantages of the HVDC options considered in this discussion paper. Note that the values included in the table assume SI generators continue to receive the share of HVDC rentals that they pay for. The values would be greater if they didn't.

Table 21 Advantages and disadvantages of HVDC options

Note – The aim is to remove this table from the document because the comparisons should have been made in the assessment of the efficiency considerations. Before this can happen there is some cross checking to be done to make sure the issues are adequately addressed.

Option	Pros	Cons
Status Quo	• Consistent with charging practice over last [11] years • May defer or prevent the need for future HVDC or AC transmission capacity.	• Disincentive to provide short-term operation in SI (low cost). • Deters investment in SI peaking capacity ($0-25m cost). • Disincentive for new generation between NI/SI ($14-51m cost) and provides an artificial competitive advantage for Meridian • Inconsistent application of beneficiary pays principle
Capacity Rights	• Should help to identify beneficiaries of HVDC transmission • Introduces an approach that could have useful application on other transmission links • Enables the market to determine a price for rights to HVDC link.	• Possible economic loss from constrained dispatch • Significant implementation issues and costs and relatively high transaction costs ($20-40m if the FTR proposal is used as a guide) • Shifts the goalpost – existing investments made under open access regime • Open to possible gaming by some market participants • Possible revenue risks or shortfall for Transpower • May require greater maturity of the market
MWh Charge	• Reduces short-term dispatch inefficiency in SI ($0-10m value). • Reduces the deterrent for investment in SI peaking capacity ($0-25m value). • Reduces the investment inefficiency from delayed SI generation ($12m value).	• Some remaining NI/SI new generation inefficiency ($9-33m cost) and still provides an artificial competitive advantage for Meridian. • Minor remaining dispatch inefficiency which could increase if there is SI thermal ($1-5m cost) • Inconsistent application of beneficiary pays principle for pole 3

Option	Pros	Cons
Postage Stamp	• Eliminates short-term dispatch inefficiency in SI ($0-10m value) • Eliminates the deterrent for investment in SI peaking capacity ($0-25m value). • Eliminates the investment inefficiency from delayed SI generation ($14-51m value) and avoids the possible advantage to Meridian. • Eliminates competition issues re SI generators receiving net FTR revenues	• Small deadweight loss from price shock ($1-2m cost) • Value shift in transition is inconsistent with good regulatory practice • Potential for dispute
Incentive free allocation to existing SI	• Would eliminate dispatch and generation investment inefficiencies, but may not be practical	• It is difficult to devise an acceptable methodology other than as part of a transition, this option had no supporters.
Postage Stamp Transition	• Eliminates short-term dispatch inefficiency in SI ($0-10m value). • Eliminates the deterrent for investment in SI peaking capacity ($0-25m value) • Eliminates the investment inefficiency from delayed SI generation ($14-51m value) and avoids the possible advantage to Meridian. • Minimises value shift and deadweight loss by avoiding price shock. • Allows the competition issue of SI generators receiving net proceeds in FTR auctions that they participate to be solved. The value impact of removing the right to HVDC rentals can be factored into the transition path.	• Costs of design (very low cost). • Potential for dispute (moderate)

5.6 The table summarising the costs and benefits, the observations and cases for alternative options are to be circulated separately

6 Assessing options or deeper or shallower connection

6.1.1 Circulated separately

7 Assessing options for static reactive

7.1.1 Circulated separately

8 Conclusion

8.1.1 To be drafted

9 Preferred option and draft guidelines

9.1.1 To be drafted

Appendix A List of questions

Appendix B Submissions summary

Appendix C Analysis supporting the assessment of HVDC cost allocation options

Introduction

C.1 This appendix sets out TPAG's analysis on:

- whether there is a potential economic cost arising from the recovery of HVDC costs from SI generators. To the extent to which there is an economic cost, this would arise from the investment inefficiency caused by the HVDC cost recovery potentially delaying cheaper SI options relative to North Island options of the next 30 years; and
- the potential value impact to end use customers from a shift of HVDC cost recovery from SI generators to customers.

Methodology for assessing possible investment inefficiency

C.2 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)[57].

C.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.

C.4 This appendix describes a simplified analysis[58] 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 investments is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options[59];
- 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 ETS costs, and approximate location factors (reflecting marginal losses) and intermittency factors[60;]

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57 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.

58 This simplified analysis is able to address some of the concerns raised by submitters with respect to the GEM model and analysis. While approximate, the analysis is very transparent, and enables a full set of sensitivities to be explored.

59 This analysis uses plausible assumptions developed from a combination of sources including the Electricity Commission (used in GEM analysis) and MED.

60 The intermittency factors take into account that different projects achieve different weighted-average prices from time-weighted prices.

- 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;
- 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 a lower gas price[61].

Constructing the merit order

C.5 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.

C.6 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 though the application of HVDC charges on SI generation projects.

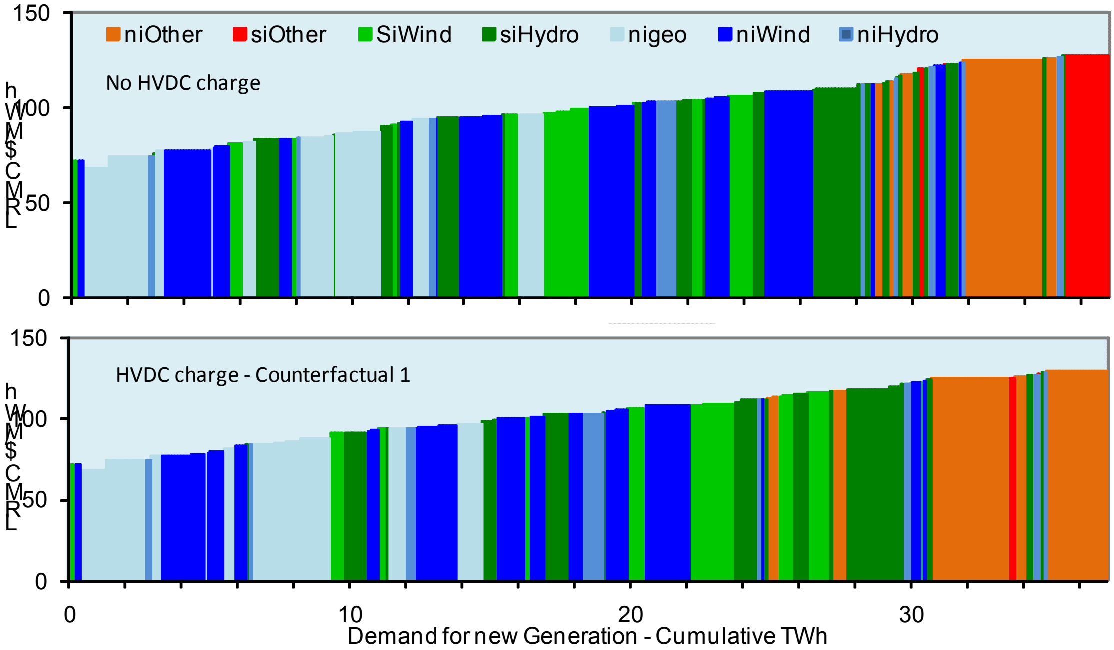
C.7 Figure 4 illustrates the two different merit orders used in this analysis, highlighting that a range of geothermal and wind projects appear to provide the cheapest development options[62]. Note that 10 TWh represents approximately 25% of today's annual electricity demand.

C.8 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.

61 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. 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.

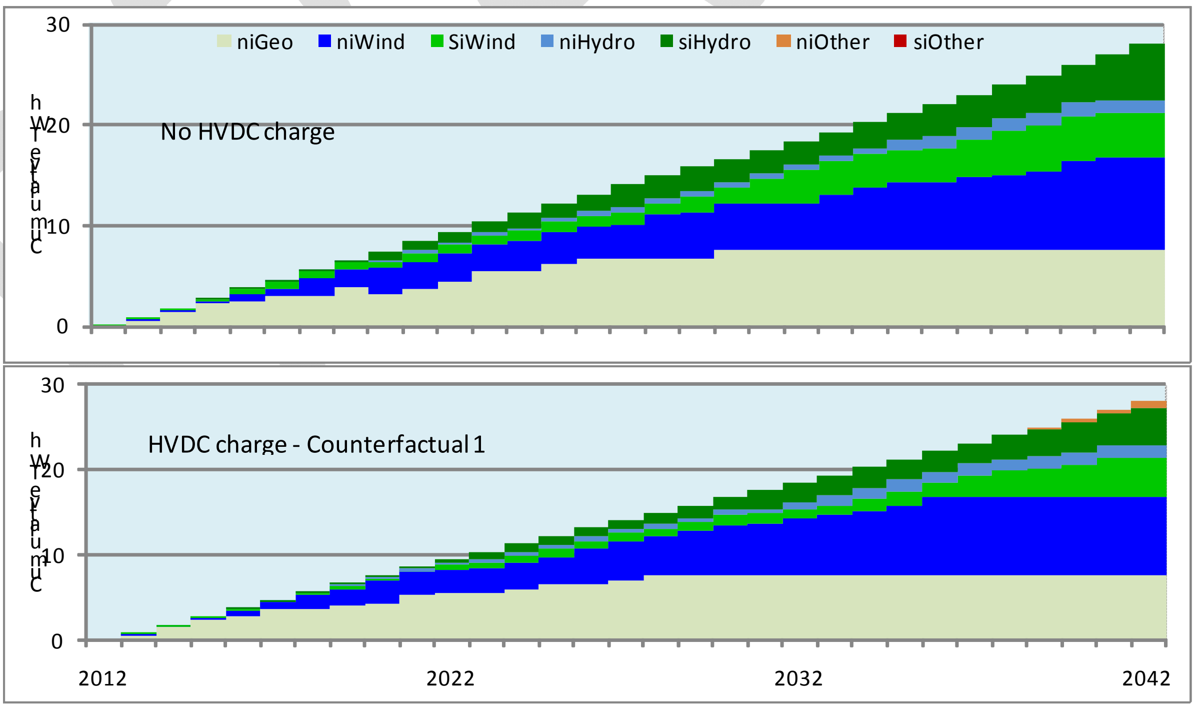
62 The long run marginal costs have been estimated using an assessed weighted-average-cost-of-capital (WACC) of 7% real post-tax. This reflects a typical commercial rate of return required by generators.

Figure 4 Illustrative merit order of new generation projects ($/MWh)



C.9 This is further highlighted in Figure 5 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.

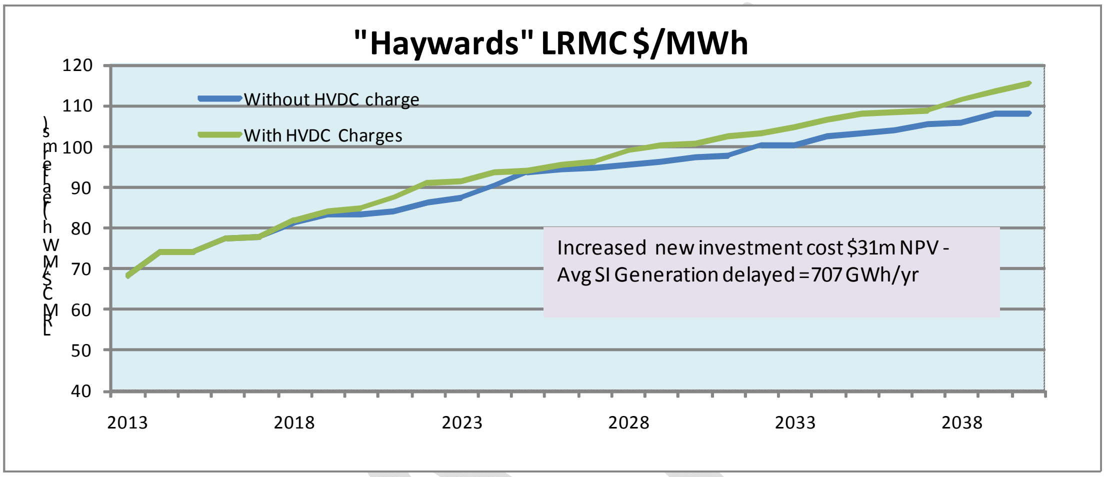
Figure 5 Illustrative impact on timing of investment



C.10 Figure 6 illustrates the potential impact on the LRMC curve which tends to feed into wholesale electricity prices. The LRMC curve is derived at the Haywards location by referring all projects to that point using the assumed average location factor for each project.

C.11 Note that in this example LRMC 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 6 Impact on the LRMC curve



Sensitivity analysis

C.12 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[63].

C.13 The analysis assumes that the average net HVDC cost under the existing price structure is $35/kW/yr in real 2011 dollar terms[64].

C.14 The analysis of the economic costs is also dependent on a number of assumptions including new investment costs, fuel costs, exchange rates and other factors. In particular, the economic cost estimate is sensitive to the relative cost and outputs of particular individual projects which are only know to within ±30%. To account for these 10 separate cases were evaluated with individual project costs being randomly varied by ± 20% around a generic capital cost for each general class of investments (geothermal, wind, hydro thermal etc).

C.15 For this reason sensitivity to these factors was tested and reported in Table 22.

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63 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.

64 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.

Table 22 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

C.16 The sensitivity analysis undertaken for a $35/kW/yr HAMI cost suggests an economic cost in a band of $14m to $51m (average $31m).

Change from HAMI cost allocation

C.17 The alternative MWh charge option described in Table 13 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.

C.18 The investment inefficiency analysis has therefore been repeated with a $7/MWh net cost. The results are summarised in Table 23 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[65].

[65] 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 not quantified in this appendix, but were estimated to be $0-25m in earlier work carried out by the Electricity Commission (Appendix 4 to the Consultation paper on Stage 2 Options, July 2010).

Table 23 Generation Investment Inefficiency with a $7/MWh HVDC cost

HVDC Cost $7/MWh	Economic Cost $m PV		Difference from HAMI	
Sensitivity	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

C.19 The sensitivity analysis for a $7/MWh HVDC cost suggests an economic cost in a band of $9m to $33m (average $20m).

C.20 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.

Opportunity cost of HVDC charges to Incumbent SI Generators

C.21 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 this may not be equal to the opportunity cost for incumbent generators.

C.22 The opportunity cost of the HVDC charges for an incumbent SI generator depends on both its share of the HVDC chares and the "counterfactual". The opportunity cost can be lower for parties who pay a high share of the costs. 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. A completely independent new SI generator will see the full HVDC cost for its new generation ($35/kW/yr), but all the incumbents will benefit from a reduction in their share of the costs. It can be shown[66] that the HVDC opportunity cost for an incumbent investing in the South Island is between 100% of the full HVDC cost ($35/kW/yr) and (1-share[67]) times the full HVDC cost depending on the investment counterfactual.

C.23 The investment counterfactuals relate to the impact of an incumbent's new SI generation investment on the investment plans of its competitors. The impact of the different counterfactuals on Meridian Energy's (the largest incumbent) HVDC opportunity cost is summarised in Table 24.

Table 24 SI generation investment counterfactuals and Impact on Meridian Energy

Option	Description	Meridian's net HVDC opportunity cost
Counterfactual 1	Large incumbent generator assumes that if it invests in the SI it will displace a competitor investment in the SI	$35/kW/yr
Counterfactual 3	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
Counterfactual 2	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 the analysis it has been assumed that the cost impact is half way between the two extremes.	$23/kW/yr

C.24 Table 25 summarises the results of the simplified analysis and suggests that the average economic efficiency loss associated with the HVDC charge could be between $24m and $42m. 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 won't be delayed as much as under counterfactual 1[68].

[66] For example see Appendix to Q5 of Norske Skog submission on Transmission Pricing Review (Sep 2010).

[67] 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.

[68] Note that the Electricity 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. 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 uncommercial 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.

Table 25 Economic cost of HVDC charge

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

C.25 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.

C.26 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.

C.27 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.

HVDC rental allocation sensitivity

C.28 The Electricity 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.

C.29 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.

C.30 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.

C.31 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.

C.32 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.

C.33 Table 26 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 26 Generation Investment Inefficiency from HVDC charges without rentals.

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

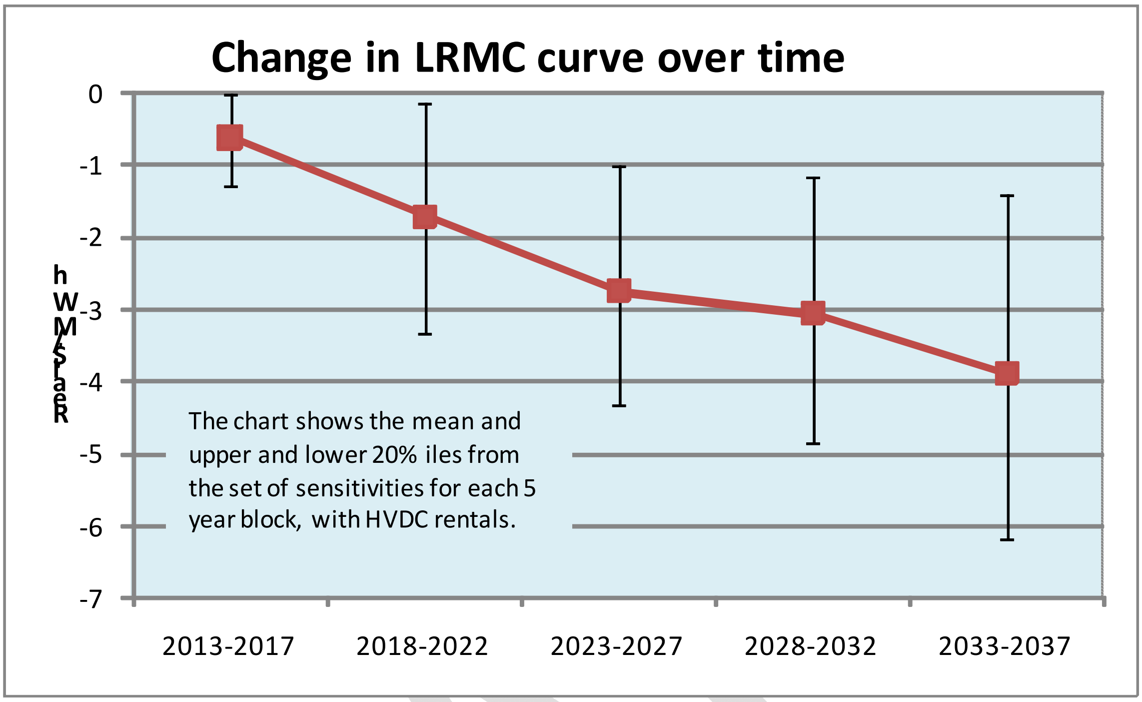
C.34 In this case the generation investment inefficiency is increased by around $6 to $8m to approximately $19-$64m (average $38m) for a HAMI allocation and $10-36m (average $26m) under a MWh allocation.

Potential Value Impact to end use customers

C.35 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.

C.36 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 7 Impact of Removal of HVDC charges on the NZ LRMC Curve



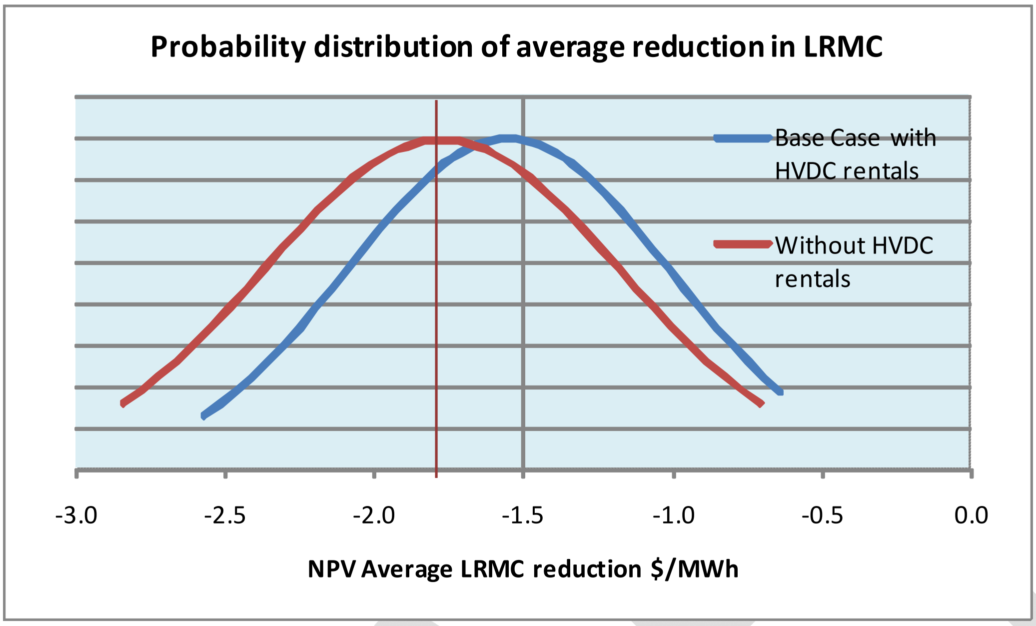
C.37 As can be seen the impact on the NZ LRMC is relatively low initially but gets greater over time. This reflects the fact that the LRMC is mainly set by low cost NI geothermal options over the next 5 years or so, but then can be set by either NI or SI generation options depending on their cost.

C.38 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.

C.39 The present value average impact on the LRMC is illustrated in the chart below[69]. This has a mean of approximately -$1.5/MWh and a standard deviation of around $0.5/MWh.

69 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 8 The Probability distribution of the PV impact on LRMC



C.40 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.

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

Background

D.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.

D.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.

D.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, 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 TPAG's deliberations, the work undertaken by the Commission and the Authority and the largely supportive submissions from participants 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.

D.4 This appendix summarises 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) TPAG's considerations.

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

D.5 The Commission considered the potential benefits for further locational in respect of future economic transmission investments[70] using its Generation Expansion Model (GEM).

D.6 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 support analysis of

[70] 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.

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

D.7 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.

D.8 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.

D.9 Appendix 3 to the Stage 2 Paper provides a description of GEM and more detail on the model is available at httilted postage stamp://gemmodel.pbworks.com .

D.10 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-optimise 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.

D.11 The analysis was based on the scenarios used for the Commission's 2010 Statement of Opportunities (SOO).

D.12 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.

D.13 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.

TPAG's considerations

D.14 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.

D.15 Submissions[71] 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.

D.16 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".

D.17 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. TPAG considers that GEM suggests sensible building patterns that are to a significant extent being played out in reality.

D.18 A number of 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.

D.19 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.

D.20 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 along the lines of the winter capacity margin.

[71] 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/

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.

D.21 TPAG considered the factors driving the analysis results. 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.

D.22 In summary, 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 be fully effective in optimally coordinating transmission and generation.

D.23 In summary, 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.