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Hon Roger Sowry
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Dear Mr Sowry

Transmission Pricing Advisory Group (TPAG) Report to the Authority

On behalf of TPAG, I attach the group's transmission pricing report to the Authority which gives effect to the key deliverable 2 in TPAG's workplan: Recommendations Paper on a preferred TPM option.

As required by paragraph 3.6 of the Authority's charter about advisory groups (advisory group charter), paragraph 6.1 of the terms of reference TPAG has endeavoured to provide consensus recommendations to the Board on matters considered by TPAG.

However, in respect of the HVDC cost allocation TPAG has been unable to reach a consensus within the agreed timeframe.

Accordingly, as required by paragraph 3.7 of part 2 of the advisory group charter, paragraph 6.2 of the terms of reference, and consistent with the Authority's guidance regarding the Biggar report, TPAG has provided a full exposition of the analysis and evidence considered by TPAG, so that the Authority can make an informed decision.

Yours sincerely,

Graham Scott

Dr Graham Scott

(Provided by E-mail)

Transmission Pricing Advisory Group

Transmission Pricing Analysis

Report to the Electricity Authority

31 August 2011

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

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Executive summary

TPAG Role and Background

1. TPAG was established in January 2011 to undertake analysis and make recommendations to the Electricity Authority on a preferred Transmission Pricing Methodology (TPM) as part of the Transmission Pricing Review (Review) initiated by the Electricity Commission and continued by the Authority.
2. In undertaking this work, TPAG has:

a) reviewed material and submissions on relevant consultation papers that were part of Stage 1 and Stage 2 of the Review;

b) considered the Authority's statutory objective and determined that the work undertaken during the earlier Stage 1 and 2 of the Review remains relevant to TPAG's role;

c) published a discussion paper and considered submissions on that paper and a report commissioned by the Authority reviewing TPAG's discussion paper; and

d) sought to achieve a consensus and make recommendations wherever possible.

3. This paper sets out TPAG's analysis and recommendations.
4. In some areas it has not been possible to reach a consensus and make a recommendation. In those areas, this report concentrates on articulating the analysis that has been undertaken and the different views that have been formed based on that analysis.

Summary of Recommendations

HVDC Cost Allocation

5. TPAG recommends that the Authority:

a) consider the analysis undertaken by TPAG on the possible efficiency losses associated with the current HVDC charges;

b) complete a GEM analysis to cross-check the size of the efficiency losses calculated by TPAG; and

c) determine whether it agrees or not with either of the following alternative views:

View 1: the HVDC cost allocation should be changed to a postage stamping with a 10 year transition arrangement because:

- the efficiency losses from the HVDC charging regime are material; and
- it is not possible to clearly and objectively identify the beneficiaries of the HVDC link and the extent of their benefits. Beneficiaries are likely to change over time and objective identification of specific beneficiaries may be difficult and problematic.

View 2: the status quo should prevail because:

- the estimates of the efficiency losses have wider error bounds than the analysis shows due to factors not captured by the analysis. In light of this, it is plausible that the efficiency losses may be closer to zero (that is, not significant);

- the estimates of efficiency gains from a transition to postage stamping are uncertain because they are measured against a counterfactual of lower long run marginal cost (LRMC) of generation than implied by the status quo;
- in contrast, the shifting of HVDC charges from SI generators to off-take customers is a certainty. Under the transition to postage stamping arrangement customers will experience a certain increase in cost and an uncertain benefit; and
- it is possible to identify that the SI generators are the primary beneficiaries; other participants may derive some benefits, but these are insufficient to argue that they should pay for the HVDC.

6. In relation to capacity rights, a range of views exists. Capacity rights would appear more costly to implement than other options, but its benefits may be significant, particularly if it reveals willingness to pay. However, if a capacity rights option were to be considered further, a range of substantial issues would need to be considered including: how it might be implemented; whether there would be benefits in its introduction at this time (rather than at the time of a major new investment in the HVDC link), and how it would fit with other market design elements such as financial transmission rights. As capacity rights would involve major market redesign, the analysis of its costs and benefits are complex and are outside the scope of TPAG's role.

Connection Charges

7. TPAG recommends that the Authority:

a) note TPAG's view that the evaluation of deeper connection options cannot be completed until Transpower's capital expenditure input methodology is determined by the Commerce Commission under section 54S of the Commerce Act 1986; and

b) consider engaging with the Commerce Commission to explore further the extent to which benefits might accrue if there is a deeper allocation of costs to customers and the possible mechanisms for implementing such a change.

Static Reactive Compensation

8. TPAG recommends that the Authority:

c) amend the Guidelines published under clause 12.83 of the Code to provide that the TPM should include a reactive power off-take charge based on a $/kvar rate;

d) amend the Connection Code in Schedule 8 of the Benchmark Agreement to remove the unity power factor requirement for the Upper North Island and Upper South Island regions and to replace this with a measure that aligns the upper region power factor requirements with the 0.95 lagging minimum that currently applies to the Lower North Island and Lower South Island regions; and

e) further consider the issues raised around alignment of the proposed pricing mechanism with the Commerce Act in respect of regulated distributors and works with the Commerce Commission to determine what improvements might be made.

Defining the Problems

9. Good public policy analysis requires a clear understanding of the problem that is being addressed, identifying options to address that problem, and assessing the costs and benefits of those options relative to the status quo.

10. It is important that transmission pricing is considered within the context of the regulatory and institutional framework that applies in New Zealand. The New Zealand framework for transmission pricing comprises the following elements:

a) transmission agreements (based on the benchmark agreement determined under subpart 2 part 12 of the Code) and the associated interconnection rules[1];

b) new transmission investments are proposed by Transpower and approved by the Commerce Commission under part 4 of the Commerce Act in accordance with an investment test[2];

c) efficient use of the grid is encouraged through nodal pricing under which grid users face the marginal cost of using the grid when making consumption or production decisions (including the marginal cost of losses and constraints but excluding full nodal scarcity costs);

d) the market surplus (loss and constraint excesses or rentals) available from nodal pricing in the wholesale market is insufficient to cover the costs of transmission.

11. Within this framework TPAG has concluded that the TPM should pursue the following objectives:

a) costs should be allocated to particular grid users on those parts of the grid where it is feasible to clearly identify the beneficiaries of the grid assets (for example, connection assets); and

b) the balance of transmission costs should be allocated in a manner that supports the efficient use of the network, or efficient investment in generation, transmission and demand-side management (DSM).

12. To give effect to the above objectives , TPAG first reviewed the Stage 1 and Stage 2 analysis. This analysis focussed initially on whether the TPM could better support co-optimised efficient investment in generation, transmission and demand-side management. TPAG agreed with the preliminary conclusion reached by the Electricity Commission that the benefits of enhanced locational signals for economic transmission investment were not significant enough to justify the costs of introducing additional locational signals[3].

13. TPAG then considered other potential problems within the existing TPM having regard to TPAG's terms of reference and the objectives above.

14. TPAG has identified the following potential problems with the existing TPM:

a) the allocation and structure of the HVDC charge is a locational signal that leads to inefficient price signals for new investment in generation;

[1] Apart from Customer Investment Contacts that typically apply at the fringes of the grid where bilateral arrangements are feasible.

[2] Noting that the Code does not preclude investment by other parties and bilaterally agreed transmission investments.

[3] The Authority is undertaking further analysis to check whether constraints implicit in the analysis of these benefits might have a material effect on the analysis.

b) the current boundary of interconnection and connection assets may not provide sufficient incentives on participants to avoid reliability-driven transmission investments and it may be feasible to clearly identify the beneficiaries of more assets than the assets currently classified as connection assets; and

c) the arrangements for minimum power factor may not provide efficient signals to grid users about the costs of reactive compensation and it may be possible to clearly identify the beneficiaries of static reactive compensation investments.

Approach to Analysis

15. The TPAG terms of reference require that in making recommendations to the Authority, TPAG must explain how any recommendations promote the Authority's statutory objective in section 15 of the Electricity Industry Act, and how TPAG has applied the Authority's Code Amendment Principles (CAPs) contained in the Authority's Consultation Charter.

16. Accordingly, TPAG has considered the statutory objective and applied the CAPs when assessing options for improving the TPM.

17. Specifically, CAP 2 requires that advisory groups only consider using the Code to regulate market activity if it can be demonstrated that amendments to the Code would improve efficiency of the industry for the long term benefit of consumers, or if a market failure is clearly identified, or if a problem is created by the existing Code, which requires an amendment to the Code or the way the Code applies (ie, a 'regulatory failure' exists).

18. TPAG has investigated the problems and concentrated on analysing possible efficiency gains from amending the Code (in this case, the TPM in schedule 12.4 of the Code).

19. CAP 3 requires that a quantitative assessment (ie, a CBA) must be applied to assess the relative efficiency benefits of the TPM options for the long term benefit of consumers.

20. In order to assess TPM options against CAP 3 TPAG found it helpful to develop some specific 'efficiency considerations' incorporating aspects of dynamic, productive and allocative efficiency as referred to in CAP 3. These efficiency considerations are summarised briefly in the following table.

Table 1 Efficiency Considerations

Consideration	Brief description
Beneficiary Pays	Apply transmission costs to particular beneficiaries where it is practical to identify them and when that application leads to net benefits.
Location price signalling	Provide additional locational price signals only where they promote more efficient use of the network and investment in transmission, generation and DSM.
Unintended efficiency impacts	Seek efficiency gains by avoiding incentives that could undermine the efficient use of the network and investment in transmission, generation and DSM.
Competitive neutrality	Provide a level playing field for long-term competition in generation and retail.

Consideration	Brief description
Implementation and operating costs	Take account of implementation, transition and operating costs.
Good regulatory practice	Adopt a consistent and durable approach that is compatible with market arrangements and avoids wealth transfers unless they are clearly justified by efficiency benefits.

21. The above efficiency considerations have been used to assess the merits of each option of each TPM option considered.

HVDC Cost Allocation

22. The current TPM allocates HVDC costs to all grid-connected SI generators with an allocation proportional to peak (kW) generation based on HAMI[4]. There are inefficiencies associated with this charge arising from:

a) disincentives for investing in SI generation relative to NI generation;

b) competition effects favouring new generation investment in the SI by large incumbent generators; and

c) generation dispatch inefficiencies arising from the HAMI price structure.

23. The analysis of these inefficiencies estimates a loss of between $31m and $57m NPV[5]. While the range is wide the size of the efficiency loss is always positive.

24. TPAG has explored the alternative HVDC charging options that were considered in Stage 2. The outcomes are summarised in Table 2. TPAG developed an additional option which involves a transition from the current arrangements to postage stamping the HVDC costs, which is also summarised in Table 2.

Table 2 HVDC options

Option	Description	Overall net benefits
HVDC Capacity rights	Generators (or other parties) would purchase capacity rights to use the HVDC link.	More costly to implement than other options. Capacity rights would involve a major market redesign. Analysis of benefits would be complex and involve analysing issues outside TPAG's role.
MWh allocation	HVDC charge would be allocated to SI generators in proportion to MWh rather than HAMI.	May be net benefits between $3m-$23m.

4 Historical Anytime Maximum Demand

5 Range determined by plus and minus one standard deviation

Option	Description	Overall net benefits
'Incentive-free' allocation to SI generators	HVDC charge would be allocated to existing SI generators in a manner that removes the inefficiencies identified above.	May be net benefits between \$29m-\$55m, although it may introduce other adverse incentives. Strong reservations about arbitrary exercise of regulatory powers that would compromise good regulatory practice.
Postage Stamp	HVDC costs would be spread broadly across off-take customers as per interconnection charge.	May be net benefits between \$28m-\$54m, but strong reservations about price impacts and wealth transfers.
Postage stamp transition	As for postage stamp, but incorporating a transitional 'incentive-free' allocation to existing SI generators	May be net benefits between \$28m-\$54m without large price impacts and wealth transfers

25. Two distinct views have emerged within TPAG about this analysis and whether it provides sufficient evidence to justify a change from the status quo. One view favours making a change to the HVDC cost allocation, while the other view supports retaining the status quo. The two views are summarised in the following table:

Table 3 Two TPAG Views on HVDC Charges

View	Make a change to HVDC charge	Make no change at this stage
Materiality of the problem	• There is a clear and material efficiency loss associated with the current HVDC charge that warrants a change from the status quo. • The potential efficiency gain is of a similar order of magnitude to other Electricity Authority priority initiatives.	• The benefits are uncertain because the analysis undertaken cannot take account of some factors that could have a large effect on investment outcomes. • Even if the analysis is correct, the efficiency loss is not material when compared with the billions of dollars of underlying investment in generation and transmission.
Recommended solution	• Transition the HVDC charge from SI generators to off-take customers by progressively incorporating the HVDC costs in the postage-stamped interconnection charges. • Undertake the transition with an initial charge to SI generators of \$30/kW/yr and transition over a period of 10 years.	• Retain the status quo with HVDC costs allocated to SI generators. • Investigate the Capacity Rights option further.

View	Make a change to HVDC charge	Make no change at this stage
Impact on consumers	• There is a low risk that consumers will see a net increase in costs and a likelihood that they will see a net decrease in costs after 10 years.	• There is a high risk that consumers will see a net increase in costs over the short and the long term if the proposed change to HVDC charges is made.

26. In relation to the impact on consumers, there are strongly held views both within TPAG and amongst submitters. It is clear that transitioning the HVDC charge from SI generators to off-take consumers via the postage stamped interconnection charge will see a gradual increase in transmission charges to consumers. The view favouring the change considers that there will be countervailing reductions in electricity prices, below what would otherwise occur, arising from the lower costs of investment in SI generation. This view was supported by a number of submitters including Meridian, TrustPower, Powershop, MRP and Transpower. The view held by others on TPAG is that those potential price reductions are uncertain, but the increases in transmission charges are certain. This view was supported by submitters including MEUG, Genesis, large users and DEUN.

27. Although the wealth transfers arising from these price impacts are not considered directly as part of the cost benefit analysis, the allocative efficiency gains are accounted for, but these are relatively small compared with other investment and productive efficiency gains. In addition, the paper considers the possible impact on prices from investment efficiency impacts and competition benefits.

28. TPAG recommends that the Authority:

d) consider the analysis undertaken by TPAG on the possible efficiency losses associated with the HVDC charges;

e) complete a GEM analysis to cross-check the size of the efficiency losses calculated by TPAG; and

f) determine whether it agrees or not with either of the following alternative views:

View 1: the HVDC cost allocation should be changed through a transition to postage stamping arrangement because:

- the efficiency losses from the HVDC charging regime are material; and
- it is not possible to clearly and objectively identify the beneficiaries of the HVDC link and the size of their benefits.

View 2: the status quo should prevail because:

- the estimates of the efficiency losses have wider error bounds than the analysis shows due to factors not captured by the analysis. In light of this, it is plausible that the efficiency losses may be closer to zero (that is, not significant);
- the estimates of efficiency gains from transitional postage stamping are uncertain because they are measured against a counterfactual of lower long run marginal cost (LRMC) of generation than implied by the status quo;

- in contrast, the shifting of HVDC charges from SI generators to off-take customers is a certainty. Under the transitional postage stamping arrangement customers will experience a certain increase in cost and an uncertain benefit; and
- the South Island generators can be identified as the main beneficiaries of the HVDC link.

Connection Charges

29. The current connection charges cover both the cost of assets provided at the point of connection with the grid, and additional 'deep connection' assets where the assets can be readily identified with particular connected entities. There may be inefficiencies associated with these charges arising from insufficient incentives to:

a) promote commercially-driven investments at the fringes of the grid;

b) provide quality information to support transmission planning and the Commerce Commission's investment approval processes; and

c) defer reliability-driven investments when it is economic to do so.

30. TPAG supports an approach that allocates costs to particular grid users on those parts of the grid where it is feasible to clearly identify the beneficiaries of the grid assets. With connection assets, it makes sense to push the boundary as deep as practical, while ensuring that the benefits of the approach outweigh any implementation and transaction costs. The flow tracing and but-for connection methodologies are an attempt to find a practical means of achieving this outcome.

31. TPAG notes that the benefits of both the flow tracing and but-for connection methodologies largely arise from the incentive for parties that are allocated costs to seek more cost-effective solutions, including non-transmission-solutions, when new reliability-driven transmission investments are being considered by Transpower and approved by the Commerce Commission. The greatest efficiencies would be achieved when the participants that are allocated costs also have decision rights.

32. TPAG identified high-level possible efficiency gains for the but-for and flow-tracing approaches and identifies a possible efficiency gain of between $15m and $40m NPV.

33. The extent to which these benefits would accrue depends largely on the effectiveness of the process incorporated in the Transpower Capital Expenditure Input Methodology (Transpower CapexIM)[6] for considering non-transmission-solutions as alternatives to investment in reliability-driven transmission assets. If this process is effective, then the benefits from any change to the connection charges would be small.

34. TPAG has explored the alternative connection charging options that were considered in the Stage 2, considered how they might impact on the efficiency losses, and the outcomes are summarised in the following table.

[6] The Commerce Commission expects to finalise the Transpower Capital Expenditure Input Methodology in late 2011

Table 4 Connection options

Option	Description	Overall net benefits
Shallow connection	Revert to a shallow definition of connection assets in order to reduce disputes about grid boundaries.	Net benefits are likely to be negative unless the application of the investment test is sufficiently robust to offset the removal of the incentives the present deep connection definition provides for grid users to participate in the investment approval process.
Flow tracing	Allocate shares of transmission costs to off-take consumers according to a 'flow trace' algorithm in order to 'deepen' the connection proportion of revenue.	It is uncertain whether the benefits would exceed the costs of implementation. Would likely introduce significant wealth transfers and price impacts between grid off-take customers depending on depth of the allocation of costs to particular customers.
But-for	Identify beneficiaries or particular grid investment at the time investment is approved and allocate costs accordingly.	It is uncertain whether the benefits would exceed the costs of implementation. Would likely introduce significant wealth transfers and price impacts between grid off-take customers. Long term investment signals might be adversely affected depending how the policy was adjusted to beneficiary changes over time.

35. The implementation of either a flow tracing or but-for connection methodology would also require coordination with the Commerce Commission, as the evaluation of the options can only be carried out in light of the operation of the yet-to-be-determined Transpower CapexIM, and the Commerce Commission would need to be able to identify beneficiaries of new reliability investments when those matters are considered under the investment test.

36. TPAG recommends that the Authority:

a) note TPAG's view that the evaluation of deeper connection options cannot be completed until the Transpower CapexIM is determined by the Commerce Commission under section 54S of the Commerce Act 1986; and

b) consider engaging with the Commerce Commission to explore further the extent to which benefits might accrue if there is a deeper allocation of costs to customers and the possible mechanisms for implementing such a change.

Static Reactive Compensation

37. The current arrangements for voltage support at grid exit points require that off-take customers meet the power factor requirements that are set out in the Connection Code. The power factor requirement for the Upper North Island (UNI) and Upper South Island (USI) is unity, and for the Lower North Island (LNI) and Lower South Island (LSI) is greater than 0.95 lagging.

38. The rationale for these requirements is that with off-take power factors close to unity, the requirement to provide static reactive compensation (SRC) equipment on the grid to meet distribution network reactive power demands at peak times is minimised.

39. TPAG has concluded that there are inefficiencies associated with current power factor requirements arising from:

a) the impracticability of off-take grid users complying with the unity power factor requirements in the UNI and USI regions; and

b) the impracticability of enforcing breaches by off-take customers of the power factor requirements in the Connection Code.

40. TPAG has further concluded that the current arrangements constitute a regulatory failure that, if not remedied, would likely lead to inefficient investments in SRC equipment.

41. TPAG has reviewed the alternative SRC options that were considered in Stage 2, identified an additional option, and considered how each option might impact on the efficiency losses. The outcomes for the two most favoured options are summarised in the following table:

Table 5 SRC options

Option	Description	Overall net benefits
Amended power factor requirement	Amend the Code to require that off-take customers are required to maintain either unity or leading power factor during regional peak demand periods.	Unlikely to provide a significant net benefit relative to the status quo. Would make compliance a more practical possibility. Off-take customers would have incentives to explore options for SRC.
Reactive power off-take charge	Introduce a reactive power charge in the form of a $/kvar rate that would apply to net average reactive power taken off the grid during regional coincident peak demand (RCPD) periods and align the minimum power factor requirement in the Connection Code across all regions at a minimum level of 0.95 lagging during RCPD periods. Reactive power charge revenue should displace an equal portion of the interconnection charge revenue.	Likely to provide a net benefit of $6m-$26m. Off-take customers would have incentives to explore options for SRC or to alternatively pay the $/kvar charge. Efficient outcomes should be achieved by setting the $/kvar charge at a level that reflects the cost of Transpower providing new regional SRC equipment.

42. TPAG notes that there are concerns expressed by some distribution businesses about the application of the Commerce Act s52P in respect of the treatment of transmission alternatives and whether costs can be passed through to consumers. This concern appears to have some validity, following the Commerce Commission's December 2010 determination in respect of Input Methodologies that apply to regulated distribution businesses.

43. TPAG has concluded that the reactive power off-take charge offers the highest net benefits and should be implemented.

44. TPAG recommends that the Authority:

a) amend the Guidelines published under clause 12.83 of the Code to provide that the TPM should include a reactive power off-take charge based on a $/kvar rate;

b) amend the Code to remove the unity power factor requirement in Schedule 8 of the Benchmark agreement for the Upper North Island and Upper South Island regions and to replace this with a measure that aligns the upper region power factor requirements with the 0.95 lagging minimum that currently applies to the Lower North Island and Lower South Island regions; and

c) further consider the issues raised around alignment of the proposed pricing mechanism with the Commerce Act in respect of regulated distributors and works with the Commerce Commission to determine what improvements might be made.

1 Introduction/purpose and scope of the paper

1.1 Purpose of paper

1.1.1 The purpose of this paper is to provide independent advice to the Electricity Authority on the development of a preferred transmission pricing methodology (TPM). The TPM is a schedule to Part 12 of the Electricity Industry Participation Code 2010 (Code).

1.1.2 Specifically, this paper gives effect to the requirement in paragraph 2.2.5 of the TPAG Workplan, for TPAG to provide a paper to the Board of the Authority which:

> "(a) provides, with supporting analysis, a preferred TPM option, and associated guidelines, for each of the following areas:
>
> (i) the allocation of all transmission costs including those that are currently categorised as connection, interconnection and HVDC costs;
>
> (ii) providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so; and
>
> (iii) static reactive compensation;
>
> (b) must provide analysis and justification to support the rejection of options, including at a minimum the options considered by the Electricity Commission in its 'Transmission Pricing Review: Stage 2 Options' consultation paper and alternatives provided by submitters;
>
> (c) must review and comment on submissions received on the discussion paper released by TPAG for submission by interested parties."

1.1.3 The Workplan reflects the requirements of paragraphs 2 (scope of role), and 3 (scope of advice) of TPAG's terms of reference.

1.1.4 In relation to some of the matters referred to above, TPAG has been unable to come to consensus recommendations. In light of that fact, as required by paragraph 6.2 of the TPAG terms of reference, TPAG has reported on alternative views based on the relevant analysis and having regard to the Authority's statutory objective, subpart 4 of Part 12 of the Code, and the Authority's Code Amendment Principles.

1.2 Summary of TPAG process to date

1.2.1 As stated in the terms of reference, TPAG has been established to:

> "(a) recommend to the Authority Board, with supporting analysis, a preferred transmission pricing methodology (TPM) option, and associated guidelines, for each of the following areas:
>
> i. the allocation of all transmission costs including those that are currently categorised as connection, interconnection and HVDC costs;
>
> ii. providing incentives for participants to take action to defer or avoid transmission investments where there are benefits in doing so; and
>
> iii. static reactive compensation;
>
> (b) provide analysis and justification to support the rejection of options, including at a minimum the options considered by the Electricity Commission in its

'Transmission Pricing Review: Stage 2 Options' consultation paper and alternatives provided by submitters; and

(c) review and comment on submissions received on:

a. the Electricity Commission's 'Transmission Pricing Review: Stage 2 Options' consultation paper; and

b. the TPAG's discussion paper containing its preferred TPM option."

1.2.2 As reflected in paragraph 3 of the terms of reference, TPAG's role involved building on earlier work, including options considered by the Electricity Commission in its "Transmission Pricing Review: Stage 2 Options" consultation paper, and submissions on that paper by interested parties.

1.2.3 Key deliverable 1, a discussion paper on a preferred TPM option, was released on 7 June 2011 (the **Discussion Paper**).[7]

1.2.4 In addition to receiving and considering submissions on the discussion paper, TPAG also received and considered a report prepared for the Electricity Authority by consultant Dr Darryl Biggar.[8]

1.3 Submissions

1.3.1 TPAG received 27 submissions on its Discussion Paper. The submissions and a summary of submissions are available from the Authority's website.[9]

1.3.2 This paper takes into account matters raised in those submissions, and, where appropriate, identifies themes or issues raised in submissions in the course of addressing the substantive issues being considered by TPAG.

1.4 The Biggar report

1.4.1 On 29 July 2011 the Authority provided TPAG with a review of TPAG's discussion paper, which was carried out by Dr Darryl Biggar (the **Biggar report**).

1.4.2 The Authority also provided guidance to TPAG regarding the treatment of the recommendations in the Biggar report. Specifically, the Authority provided guidance on:

a) Dr Biggar's concerns regarding TPAG's understanding of the underlying problems and the analysis framework adopted by TPAG;

b) To what extent TPAG should consider each of Dr Biggar's 13 recommendations.

1.4.3 As recognised by the Authority in its guidance, Dr Biggar's report raises broad questions about the regulatory framework and raises other issues that are outside the scope of TPAG's role. In light of this, and consistent with paragraph A19 of the Authority's guidance, TPAG has not considered or made recommendations relating to matters not within the scope of TPAG's role as set out in the terms of reference.

1.4.4 However, consistent with the Biggar report and comments from submitters, TPAG has endeavoured to more clearly articulate the problem that it is seeking to address in considering

7 Available at: http://www.ea.govt.nz/document/14039/download/our-work/consultations/advisory-group/transmission-pricing/

8 Independent Review of "Transmission Pricing Advisory Group: Transmission Pricing Discussion Paper: 7 June 2011", available from http://www.ea.govt.nz/document/14525/download/our-work/advisory-working-groups/tpag/1Aug11/

9 Submissions are available at: http://www.ea.govt.nz/our-work/consultations/advisory-group/transmission-pricing/submissions/

options for a TPM as required under paragraph 3 of TPAG's terms of reference. This paper includes a specific section setting out the problem statement (section 3).

1.4.5 Otherwise, where appropriate, this paper specifically addresses matters raised in the Biggar report having regard to guidance provided by the Authority.

1.5 Consensus views

1.5.1 As required by paragraph 3.6 of the Authority's charter about advisory groups (advisory group charter), paragraph 6.1 of the terms of reference TPAG has endeavoured to provide consensus recommendations to the Board on matters considered by TPAG.

1.5.2 However, in respect of the HVDC cost allocation TPAG has been unable to reach a consensus within the agreed timeframe.

1.5.3 Accordingly, as required by paragraph 3.7 of part 2 of the advisory group charter, paragraph 6.2 of the terms of reference, and consistent with the Authority's guidance regarding the Biggar report, TPAG has provided a full exposition of the analysis and evidence considered by TPAG, so that the Authority can make an informed judgment.

1.5.4 Finally, TPAG was mindful of the Authority's requirement for TPAG to make a recommendation by the end of August 2011, in order to facilitate the option of enabling the TPM to be revised in time to allow any changes to be implemented by April 2013.

2 Background to the transmission pricing methodology

2.1.1 Clause 12.78 of the Code states that the purpose of the TPM is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic cost of Transpower's services are allocated in accordance with the Authority's objective in section 15 of the Act.

2.1.2 That is, despite its name, the TPM is an allocation methodology, rather than strictly a pricing methodology. Transpower's prices are regulated by the Commerce Commission under an individual price-quality path set under Part 4 of the Commerce Act.

2.2 Core aspects of the current TPM

2.3 Under the current TPM, transmission customers face three charges:

a) Connection charge: The purpose of the connection charge is to allocate the costs of connection as far as possible on a 'user pays' basis. For example, the connection charge recovers the cost of dedicated and spur line assets connecting a participant to the interconnected grid. Distribution companies, generators and large consumers connected directly to the grid pay a connection charge.

b) Interconnection charge: The purpose of the interconnection charge is to recover the balance of Transpower's AC revenue requirement not covered by the connection charge. Interconnection charges are determined on a regional basis, and postage stamped to offtake customers based on each customer's contribution to peak demand. Only distribution companies and large, directly-connected consumers pay an interconnection charge.

c) HVDC charge: The purpose of the HVDC charge is to recover the cost of the HVDC link from the owners of South Island generation plant.

2.3.2 To determine the connection charge it is necessary to address a range of elements, which are grouped into two categories as follows:

- assigning assets to customers. This includes:
    - geographical grid definition, the links-nodes definition, and the definition of connection asset (together these matters comprise the 'deep versus shallow' connection issue);
    - treatment of assets shared between customers;
    - treatment of land assets shared between connection and interconnection;
    - treatment of other assets shared between connection and interconnection;
- calculating the connection charge:
    - the use of a valuation allocation methodology for connection assets;
    - maintenance costs relating to connection assets;
    - connection assets operating costs;
    - the connection charge calculation.

2.3.3 To determine the interconnection charge it is necessary to address four pricing elements:

- the regional definition – ie, grouping of GXPs into regions;
- the number of peak demand periods;

- the coincident peak allocation; and
- the period over which demand is measured (the capacity measurement period).

2.3.4 To determine the HVDC charge, Transpower uses historical anytime maximum injection (HAMI) information.

2.3.5 The TPM also addresses the following:

- charges for new connections;
- prudent discounts that may apply to avoid inefficient bypass;
- how to recover the costs of transmission alternatives, if it is necessary to fund such investments;
- transitional arrangements if necessary to address changes to the TPM.

2.3.6 As required by TPAG's terms of reference, TPAG's work has concentrated primarily on the 'deep versus shallow' connection issue under the connection charge, HVDC charging, and whether it is desirable to amend the TPM to allocate costs for static reactive compensation (the TPM currently prohibits the allocation of costs for assets relating to voltage).

2.4 Transmission pricing

2.4.1 The fundamental objective of any transmission pricing arrangements should be to support the efficient use of the network, and efficient investment in generation, transmission and demand-side management. This objective is often achieved in other capital intensive markets through contracting arrangements – contracts entered into between willing buyers and willing sellers provide an efficient framework for use of and investment in capital intensive assets.

2.4.2 In transmission networks however, economies of scale, monopoly characteristics, and common good aspects, all make it difficult for a pure contracting model to work efficiently. For this reason, transmission regulation around the world has tended to focus on transmission investment, revenue determination, and efficient transmission pricing methodology.

2.4.3 The efficient use of the transmission network requires that network users pay and receive prices that reflect the marginal cost of electricity at different points on the network. This ensures that users face the marginal cost of using the transmission network at any point in time and at any location in the network, when making consumption or production decisions. In New Zealand, wholesale prices are based on nodal prices (also known as locational marginal prices) for this reason.

2.4.4 The initial thinking in New Zealand (and elsewhere around the world) was that nodal pricing would give rise to the possibility of market-driven pricing and investment of transmission services. At least in principle, grid users would have an incentive to enter into investment contracts with Transpower to augment parts of the network in order to reduce the ongoing costs of the losses and constraints that would otherwise be incurred. However in practice nodal pricing (as implemented in New Zealand) has not proved sufficient on its own to encourage efficient market-driven investment in the transmission network.

2.5 Transmission Pricing in New Zealand

2.5.1 Over the last 25 years the electricity sector in New Zealand has been progressively reformed and the regulatory environment has been progressively developed. This has had particular implications for transmission pricing (see highlighted box – History of Transmission Pricing in New Zealand).

History Of Transmission Pricing in New Zealand	
Pre 1987 Centralised government	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a government department.
1988 to 1996 Corporate model	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a subsidiary of ECNZ – a state-owned integrated electricity generating and transmission business.
1996 to 2003 Market-based arrangements	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The process was no-longer centralised and coordinated with generation investment and there was an expectation that grid users would contract, on a disaggregated basis, with Transpower for the services that they required. Grid investments needed to be underpinned by these contractual arrangements. Closing off contractual negotiations proved very difficult and transmission investment, particularly on the 'core grid', largely stalled.
2003 to 2010 Electricity Commission	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The EGRs regulated the transmission investment process and over time the investment approval process, the Grid Reliability Standards (GRS), and the Grid Investment Test (GIT) were developed and incorporated in the Rules.Transpower applied the GIT and made investment proposals. The Electricity Commission was responsible for approval of investments.
2011 Commerce Commission	Transmission investment is undertaken by Transpower – an independent state-owned transmission business. The investment approval process is now overseen by the Commerce Commission. The GIT (to be replaced by an Input Methodology) remains central to the process.

2.5.2 By 1996 competition in the generation and retailing of electricity had been established, the transmission grid had been separated from generation, and a light-handed regulatory regime was in place. Under these arrangements it was expected that:

a) any new investment in transmission would be underpinned by contracts negotiated through a series of bilateral agreements between Transpower and its customers;

b) these contracts would specify the service obligations and payment obligations;

c) any new investment in transmission would only proceed if Transpower could secure appropriate contracts to underpin the cost.

2.5.3 Over the period from 1996 to 2003 the electricity sector grappled with how to invest in, and contract for, transmission services, within a self-regulatory framework. During this period:

a) there were ongoing disputes about how the costs of the HVDC transmission should be allocated;

b) disagreements over the appropriate means of contracting for transmission services dictated that Transpower relied upon posted terms and conditions, rather than agreed contracts; and

c) Transpower was not able to secure contracts to underpin any major investment in the transmission grid.

The result was that grid investment stalled and there was ongoing uncertainty about transmission service obligations and transmission pricing.

2.5.4 In order to address these problems[10] electricity sector participants formed the Electricity Governance Establishment Committee in 2001 to oversee a process designed to implement a more collective multi-lateral approach to self-regulation. As part of these arrangements a work-stream aimed at resolving the impasse over transmission contracting and investment was pursued through 2001 and 2002. Although some progress was made, a workable multi-lateral arrangement for making investment decisions and contracting for transmission services was not able to be agreed.

2.5.5 In 2003 the Government established the Electricity Commission in part to regulate transmission investment and arrangements for contracting transmission services[11]. In adopting this approach New Zealand was following the lead of most electricity markets around the world, where it is now generally accepted that the 'contractual' transmission model will fail to deliver an optimum transmission grid as a result of:

a) the locational price differences available from nodal pricing being insufficient to justify investment in augmented transmission assets[12];

b) difficulties in establishing a collective agreement where the sum of private benefits equates to the national benefit; and

c) economies of scale that suggest it is in the national benefit to make large investments in transmission that provide value over a long time-frame.

2.5.6 There is a marked contrast between the arrangements that prevailed over the period 1996-2003 and the current regulatory arrangements established in November 2011. This is highlighted in Table 6.

[10] Amongst other problems with the approach to regulation of the electricity sector.

[11] Amongst other matters.

[12] In part this is because the value of scarcity is not always incorporated in locational prices at each location in the network.

Table 6 Contrasting Regulatory Arrangements for Transmission

Feature	1996-2003	2011
Transmission Contracts	• Bilateral contracts agreed between Transpower and customers. • Generally 'posted terms' applied.	• Transmission contracts and the interconnection rules are overseen by the Electricity Authority. • Default contracts determine the service obligations. • Commerce Commission may determine quality standards but those standards must be based on and consistent with quality standards set by the Electricity Authority. • Electricity Authority determines reliability standards.
Transmission revenues	• Determined by Transpower and included in 'posted terms'.	• Transmission revenues are determined by the Commerce Commission.
Transmission investment	• All investments needed to be underpinned by contracts.	• New investments in the transmission grid are proposed by Transpower and approved by the Commerce Commission, based on a electricity markets benefit test. • Contract-based investments are still possible, but tend to be limited to some connection assets.
Transmission pricing methodology	• Determined by Transpower and included in 'posted terms'.	• Allocation of transmission cost is determined by a TPM overseen by the Electricity Authority.

2.5.7 The New Zealand framework within which transmission pricing methodology needs to be considered is therefore one in which:

a) contract-based transmission investments tend to be limited to connection assets where it is feasible to clearly identify the grid use;

b) the bulk of new transmission investments are proposed by Transpower and approved by the Commerce Commission under part 4 of the Commerce Act in accordance with an investment test;

c) efficient use of the grid is encouraged through nodal pricing under which grid users face the marginal cost of using the grid when making consumption or production decisions (including the marginal cost of losses and constraints but excluding full nodal scarcity costs);

d) the market surplus (loss and constraint excess or rentals) available from nodal pricing in the wholesale market is insufficient to cover the cost of transmission; and

e) it is necessary to allocate additional costs to grid users to recover the full costs of transmission.

3 Problem statement

3.1 Introduction

3.1.1 This section sets out a statement of the problems identifying the potential failures and inefficiencies that TPAG has analysed. This section has been included partly in response to the Biggar Report and submitter comments. In particular, the Biggar report suggested that the Discussion Paper did not articulate a coherent set of problems or issues with the current regime and in particular did not include a clear identification of the problem or 'market failure' and the targeting of options to those problems.

3.1.2 The term 'market failure' in welfare economics derives from the assumption that a competitive market delivers efficient pricing, production, consumption and investment, for the long-term benefit of consumers. Any departures from perfect competition that might impact on efficient market outcomes are often referred to as market failures. As this can be artificial and ignore the practicalities of continuous refinement of regulatory policies, this paper seeks to identify inefficiencies in the status quo and propose measures to reduce these within the requirements of the CAPs and in the long term benefits of consumers.

3.1.3 The Review as part of which TPAG is providing advice, has sought to understand the problems in transmission pricing in New Zealand, propose options that may provide remedies and undertake cost benefit analysis to determine whether there is justification to make changes to the TPM.

3.1.4 TPAG's work follows a substantial body of analysis for the Review by the Electricity Commission and subsequently the Authority as well as analysis by participants.

3.1.5 In the early stages of TPAG's work it concluded that, although there have been changes to the statutory framework during the course of the Review, the Commission's analysis and development of alternative options does not need to be reworked and that the options developed were developed in a manner consistent with the Authority's statutory objective. Submitters to the TPAG Discussion Paper generally agreed.

3.1.6 Despite this, the initial stages of TPAG's work involved understanding the economic theory and earlier analysis undertaken by the Commission.

3.1.7 This section first considers the analysis undertaken in Stages 1 and 2 of the Review which identified problems in transmission pricing in New Zealand and considered options targeted at remedying the problems. Building on the conclusions of Stages 1 and 2 (which TPAG reconsidered) this section then describes the problems that TPAG has analysed.

3.2 Identifying high-level problems and options (Stage 1 Analysis)

3.2.1 Stage 1 of the Review investigated efficient pricing theory, international experience and issues with the current TPM, and identified high level options for modifying the TPM.

3.2.2 Under the Electricity Commission, the Review initially concentrated on whether transmission charges should be structured to include further locational signalling. The Commission's work indicated that there were likely to be economic reasons why the existing market arrangements might fail to deliver the most efficient co-optimisation of generation, demand and transmission.

3.2.3 The analysis was undertaken by Frontier Economics[13]. Frontier commented that an energy market with 'full' nodal pricing ought to provide efficient signals for the use of the existing transmission network. That is, a market with full nodal pricing should provide appropriate signals for participants' operational decisions.

3.2.4 Frontier further noted that full nodal pricing may not provide appropriate signals for investment by generation and load. This is because a number of factors suppress the nodal pricing signals; the economies of scale in investment, the over-caution of network planners and regulators, and a lack of full nodal scarcity pricing.

3.2.5 Frontier suggested a number of high-level options targeted at providing additional locational signalling to improve the optimisation of generation, load and transmission investment.

3.2.6 These issues considered by Frontier are similar to the first issues that the Biggar Report suggests a regulator should consider in respect of transmission pricing[14].

3.2.7 In parallel with the Commission's Stage 1 analysis, NERA[15] undertook analysis of transmission pricing for the CEO Forum and reached conclusions, amongst others, that, although the current arrangements ensure the short-run marginal cost of transmission are signalled to market participants, the combination of nodal pricing, losses, the deep connection charges and the grid investment test (GIT) may not be sufficient to signal the long-run marginal cost of transmission investment.

3.2.8 The high level options included in the Stage 1 Consultation Paper were:

a) **Status Quo** – the current transmission pricing arrangements were included as a high-level option. The Stage 1 consultation paper also asked submitters if there were possible minor modifications that could be made to the current arrangements.

b) **Tilted Postage Stamp** (TPS) – this approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing comparatively higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.

c) **Augmented Nodal Pricing** – this approach seeks to directly address possible deficiencies in nodal energy prices. Under this regime transmission charges should be highest for those generators and loads that benefit most from network investment, and transmission charges should be lowest for those generators and loads that benefit least from 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

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13 Available at: http://www.ea.govt.nz/document/6613/download/our-work/programmes/priority-projects/transmission-pricing-review/

14 Biggar Report, p26.

15 New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group, NERA, August 2009, available at: http://www.ea.govt.nz/document/6616/download/our-work/programmes/priority-projects/transmission-pricing-review/

reflective network pricing (CRNP)) or on forward-looking network development costs, as in Great Britain (investment cost related pricing (ICRP)).

3.2.9 The Stage 1 Consultation Paper also identified four other issues to be addressed by the Review:

a) the approach to setting connection charges;

b) the treatment of transmission alternatives;

c) linking transmission pricing with service quality; and

d) static reactive power compensation.

3.3 Analysing the benefits of additional locational signals and investigating high-level options (Stage 2 Analysis)

3.3.1 The second stage of the Transmission Review drew on submitters' views and analysis of the potential benefits of locational signalling. The Stage 2 consultation paper signalled two important provisional conclusions:

a) there does not appear to be a demonstrable benefit from enhanced locational signalling to grid users to defer economic transmission investments through transmission charges; and

b) there appears to be a possible benefit from options that provide incentives to avoid or defer reliability-driven investments (for example, through investment in generation or load management).

3.3.2 The Stage 2 consultation paper came to a preliminary conclusion that there was unlikely to be merit in pursuing high-level options that introduced further locational signalling for economic transmission investments. The paper noted that this could have implications for the design of the HVDC charge as it sends a locational signal to invest in generation in the NI in preference to the SI. The paper considered the costs and benefits of the operational and investment signals in the current HVDC charge.

3.3.3 The Stage 2 consultation paper suggested options for modifications to the status quo for:

a) incentivising the deferral of reliability transmission investments;

b) the allocation of High Voltage Direct Current (HVDC) costs; and

c) static reactive compensation (SRC).

3.3.4 TPAG has spent some time understanding and testing the Stage 2 analysis of the value of locational signalling for economic transmission investment because the conclusions leading from this analysis have been pivotal to the direction of the Review and the work of TPAG (for a description of the work undertaken see the highlighted box – Investigating the benefits of enhanced locational price signals).

3.3.5 This work suggests that the upper bound estimate of the benefit that might be available is between zero and $30m NPV. TPAG notes that this is an upper bound estimate because the analysis assumes that it would be possible to design a locational pricing methodology that delivered perfect signals to generation investors about the cost of locating new generation at all locations on the grid.

3.3.6 In response to submitter and Biggar Report concerns, TPAG has, in addition, asked the Authority to undertake further sensitivity testing, particularly to check whether constraints implicit in the analysis might have a material affect on the analysis.

3.3.7 In practice, any locational pricing methodology would likely deliver relatively blunt pricing signals that could be expected to deliver only a portion of the upper bound benefits. This observation, when combined with the costs of implementing and administering a location-based TPM, persuaded TPAG members to favour the Commission's provisional conclusion that there does not appear to be significant economic benefit from enhanced locational signalling to grid users through transmission charges to defer 'economic transmission investments'.

3.3.8 It is important to note that this conclusion is only relevant for 'economic transmission investments' and may not be relevant for 'reliability transmission investments'. The Biggar Report questioned this distinction and TPAG has further considered the distinction.

Investigating the benefits of enhanced locational price signals – the GEM experiment	
Rationale	A central part of the Stage 2 analysis was the assessment of the potential benefits of further locational signals to encourage better co-optimisation of investment in generation, load and transmission.
GEM	GEM is a capacity expansion model used for long term 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 that minimises total system costs while satisfying a range of technical, economic and policy constraints. The costs that GEM keeps track of and minimises over the modelled time horizon (31 years from 2010 until 2041 for the Stage 2 analysis) include capital expenditure for new generation plant and transmission upgrades, fixed and variable operating costs, certain classes of reserves, HVDC costs, and unserved energy. GEM is provided with a list of 280 potential new generating plant, each with a fixed capacity, and specific to a particular location. Given forecasts of demand, fuel costs, carbon costs, historical hydrological sequences, a discount rate, capital costs and other input parameters, GEM seeks to satisfy the forecast demand by building the least-cost mix of plant. A key output of the model is the resulting build schedule, i.e. a schedule of new generation plant by year and location. When operated in such a multi-regional mode, GEM is able to co-optimise generation and transmission expansion. This means that the decision about what plant to build where and when can be simultaneously considered along with the decision to commission grid upgrades. Total system cost minimisation remains the objective of the model.
Experiment	GEM was used to derive an upper bound estimate of the national benefit available by configuring the model in two ways: • To optimise the future generation build while ignoring possible interconnection costs (to mirror a ‘postage stamp’ pricing regime) • To co-optimise future generation build and interconnection investments simultaneously (to mirror a perfect generation price signalling regime) The difference in cost between the two GEM solutions represents the upper bound estimate of the benefit of allowing generation developers to respond to locational price signals

Investigating the benefits of enhanced locational price signals – the GEM experiment	
SOO Scenarios	Scenario techniques are typically adopted if the range of plausible future uncertainties is sufficiently wide that decision-making or planning outcomes would be markedly different under different states. Projecting transmission requirements over the economic lifetime of generation and transmission assets is such a situation. The approach generally involves developing a set of scenarios intended to encompass a credible range of future uncertainties. The 2010 SOO adopted the following five scenarios: • **2010 Sustainable path** – focus on renewable generation and reduced thermal production • **2010 SI wind –** rapid wind farm development • **2010 Medium renewables** – focus on renewable generation. Tiwai smelter is decommissioned • **2010 Coal** – low carbon charge and gas discoveries lead to a focus on gas and coal plants • **2010 High gas discovery** – new gas discoveries lead to a focus on high-efficiency gas-fired CCGT and peakers
Results	The experiment suggested that the upper bound benefit that could be available was likely to be positive but small (between zero and $30m NPV, mean $14m).

3.3.9 In the New Zealand system, in particular, it is useful to categorise transmission investments as 'economic' or 'reliability' because of the fundamentally different drivers for the two types of investment and because transmission investments tend to fall clearly into one category or the other.

3.3.10 New Zealand may be unusual in this respect, relative to many other countries where the distinction is less clear[16]. This is because the New Zealand system is relatively long and 'stringy' and generation is heavily based on intermittent renewable supply options.

3.3.11 The distinction made in New Zealand is between:

a) 'economic investments' where the primary benefit is minimising energy costs by reducing constraints and transmission losses in the network; and

b) 'reliability investments' where the primary benefit is minimising unserved energy and/or meeting a deterministic reliability standard.

3.3.12 The background to this distinction is more fully explored in the highlighted box: The New Zealand Transmission System – economic and reliability investments.

3.3.13 The second provisional conclusion from the Stage 2 analysis was that there may be a benefit in transmission pricing options that provided incentives to avoid or defer reliability-driven investments (for example, through investment in generation or load management).

[16] For example, in Australia generation is heavily based on thermal power stations and it is feasible to undertake all transmission planning using a probabilistic assessment of the costs and benefits.

The New Zealand Transmission System – economic and reliability investments
Transmission investments are generally undertaken to either reduce expected unserved energy to consumers (reliability investments), or to lower the costs of supplying electricity to consumers (economic investments). A reliability investment could be made to enable continued firm supply to a growing load. An alternative to the reliability investment could be local peaking generation or demand response.
An economic investment could be made to enable a relatively lower cost generation resource to be developed, or to reduce transmission losses, or to reduce transmission congestion and enable lower cost generation to be dispatched to meet demand. In a renewables-dominated system such as New Zealand, economic investments are often made to enable better use of existing renewable generation, or to enable development of lower cost renewable resources. An investment in renewable generation could also act as an alternative to a reliability-driven transmission investment, but ideally it would need to provide firm generation (for example geothermal or hydro with storage) and would need to be close to load.
The distinction between reliability investments and economic investments is not always apparent since all transmission investments will tend to reduce unserved energy and lower the cost of supplying electricity. However, the distinction is a useful one in a New Zealand context.
There are a number of reasons why the categorisation of transmission investments into the two varieties will make more sense in a renewables-dominated system than a thermal system. Firstly, in a renewables system, intermittent generation will need to be firmed by other generation. Transmission linking firming generation, or 'firm locations', to load will be reliability driven, and reliability investments may be deferred by locating new firming generation or demand response near load. Secondly, renewable resources are less likely to be located near to load, and new transmission investments will be made to develop the resource. Finally, the presence of hydro generation, seasonal storage and firming plant, means that transmission investments may only provide flexibility in the scheduling of generation over long time frames, resulting in reduction in water or wind spill (valued at LRMC) caused by constraints.
In contrast, in a thermally-dominated system, the presence of a transmission constraint can impose not only an inefficient use of fuel, but is also more likely to impact on reliability; effectively all plant is firm, so lack of transmission capacity may hamper the reliable supply of load.
In the New Zealand system, renewable resource is not generally located such that the development of that resource with firm renewable generation could defer transmission investments to serve load. A possible exception would be the upper South Island, where hydro development could defer transmission into Christchurch. This means that the analysis of transmission pricing is generally able to separately consider two smaller problems; the impact of transmission pricing regimes on the co-optimisation of renewable generation and economic transmission investments, and the co-optimisation of peaking or short term firming generation and reliability driven transmission investments.

3.3.14 The Stage 2 consultation paper identified options to incentivise the deferral of reliabiilty investments:

a) bespoke postage stamping involving a higher charge on loads and credits to generators in particular regions;

b) a ‘flow-tracing’ approach to allocating the cost of interconnection assets to specified parties, possibly coinciding with a shallower approach to defining connection assets;

c) improving the transmission alternatives regime.

3.3.15 TPAG reviewed this work and concluded that there was little benefit in pursuing some of the ‘bespoke’ pricing options identified in Stage 2 because of two factors:

a) the existing RCPD interconnection charges already provide a stronger signal for demand management in potentially constrained regions with growing demand relative to other regions;

b) the application of the investment test includes a transmission alternatives regime with similar characteristics to some variants of the 'bespoke' pricing options.

3.3.16 TPAG concludes that 'bespoke' pricing options are unlikely to deliver additional benefits and risk conflicting with the existing RCPD mechanism.

3.4 Conclusion: problem definitions for TPAG's analysis

3.4.1 It is generally accepted that good public policy analysis requires, as a first step, a clear understanding of the underlying problem that is being addressed. The second step is to identify a set of options to address that problem, and the third step is to assess the costs and benefits of those options relative to the status quo.

3.4.2 As TPAG's scope of work has been determined by its terms of reference as set out in section 1 , its analysis has been concerned with possible problems or failures with the TPM rather than with the wider market and regulatory context.

3.4.3 TPAG has considered problems with the TPM with reference to the overall framework of which the TPM is a part. This is a framework in which, among other things, a transmission investment must satisfy an investment test and by approved by the Commerce Commission before Transpower can be sure that it can recover the costs of the investment (rather than contractual arrangements between Transpower and its customers) and the losses and constraints surpluses are insufficient to cover the cost of transmission. TPAG has not analysed wider problems with the regulatory and market arrangements (if any) that might call this framework into question. Consideration of such issues would involve deeper questions, including revisiting previous policy decisions, and are outside the scope of the TPAG terms of reference.

3.4.4 The paper produced by Frontier Economics[17] and the Stage 1 and Stage 2 Consultation Papers were intended to identify the underlying problems, identify a set of options, and to assess the costs and benefits of those options.

3.4.5 TPAG has reviewed this material, and agrees with the Stage 1 and 2 conclusions that:

a) nodal pricing provides efficient signals for the short-term use of the network, but insufficient market surplus (rentals) to fully fund transmission costs;

b) the benefits of enhancing locational signals for economic transmission investments are not sufficient to justify changing the TPM to provide additional locational signalling for economic transmission investments; and

c) the combination of nodal pricing, interconnection charges, connection charges, and the HVDC charge may not provide efficient price signals for co-optimisation of investment in generation and load and transmission.

3.4.6 TPAG has also concluded that the overall objective of the TPM within the regulatory and market framework that it operates within should be to:

[17] Identification of high-level options and filtering criteria; Frontier economics available at: http://www.ea.govt.nz/document/12313/download/our-work/consultations/transmission/tpr/

a) allocate costs to particular grid users on those parts of the grid where it is feasible to clearly identify the beneficiaries of the grid assets (for example connection assets); and

b) allocate the balance of transmission costs in a manner that supports the efficient use of the network, or efficient investment in generation, transmission and demand-side management.

3.4.7 Considering the Stage 1 and 2 analysis and submissions and undertaking its own analysis TPAG identified the following potential problems with the TPM:

a) the allocation and structure of the HVDC charge is a locational signal that leads to inefficient price signals for new investment in generation;

b) the current boundary of interconnection and connection assets may not provide sufficient incentives on participants to avoid reliability-driven transmission investments when it would be efficient to do so and it may be feasible to clearly identify the beneficiaries of more assets than the assets currently classified as connection assets; and

c) the arrangements for minimum power factor may not provide efficient signals to grid users about the costs of reactive compensation and it may be possible to clearly identify the beneficiaries of static reactive compensation investments.

3.4.8 In addition, TPAG notes that the RCPD allocation approach is an existing locational signal, and there may be opportunities for fine-tuning this approach but has concluded that Transpower is better placed to make this assessment. The RCPD mechanism was developed by Transpower in response to the March 2006 Guidelines for the TPM. Any revised guidelines should include a provision for Transpower to review the ongoing appropriateness of the RCPD settings.

4 Analysis Framework

4.1 Introduction

4.1.1 TPAG's terms of reference set out requirements for the provision of advice and recommendations to the Board (Section 6 of the TPAG terms of reference).

4.1.2 In particular, clause 6.4 of the terms of reference states the following:

> ' 6.4 In making recommendations to the Board, the TPAG must explain how the recommendations promote the Authority's statutory objective, are consistent with subpart 4 of Part 12 of the Code, and how the TPAG has applied the Authority's Code amendment principles (as published in Part 1 of the Authority's consultation charter) to arrive at its recommendations.'

4.1.3 This section describes:

a) the application of the CAPs to the TPAG's analysis framework; and

b) the identification of efficiency considerations to assist the TPAG in its CBA.

4.1.4 Submitters and the Biggar Report commented on the analysis framework set out in the Discussion Paper. This section reflects TPAG's consideration of the submitters' and Biggar Report views.

4.2 The application of the CAPs

4.2.1 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.

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

Table 7 The application of CAPs 1 to 3 to TPAG's analysis framework

	Interpretation	Application
CAP 1	Lawfulness: any change to the TPM must be lawful and consistent with the Act, come within the Authority's jurisdiction and in particular be consistent with the statutory objective. This means changes to the TPM must promote efficiency, competition and reliability for the long term benefit of consumers.	The Authority's jurisdiction under the Act includes proposed Code amendments to the TPM. The analysis under CAP 2 and CAP 3 will test consistency with the statutory objective.
CAP 2	Clearly identified efficiency gain: any change to the TPM must demonstrate a clear efficiency gain or resolve a market or regulatory failure for the long term benefit of consumers.	The TPAG has considered problems with the status quo to identify potential efficiency gains for the long term benefit of consumers.

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

4.2.3 CAP 2 is not instructive on the question of required 'materiality' for an identified efficiency gain or regulatory or market failure. TPAG has taken this to mean that where a possible efficiency gain or regulatory or market failure is identified, options should be developed to capture the efficiency gain or remedy the market or regulatory failure. The CBA (CAP 3) will provide guidance on whether there is justification to proceed with a change.

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

a) Is there a proposal to amend the Guidelines and the TPM which would result in a net improvement (efficiency gain or regulatory or market fix) for the long term benefit of consumers (CAP 2)?

b) Have the correct options been identified?

c) Have the costs and benefits of each option been correctly identified and what is the level of confidence that they will be realised? (CAP 3)?

d) Comparing the options, which option has the highest combined net benefit associated with the highest likelihood of capturing the benefits and minimising the costs (CAP 3)?

4.2.5 To provide a structure to consider the costs and benefits of the options, the TPAG has identified a number of efficiency considerations which form the basis of its CBA.

4.3 Biggar Report general concerns over the use of the CAPs and the efficiency considerations

4.3.1 The Biggar Report identified concerns around the appropriateness of the CAPs in carrying out public policy analysis and in providing a foundation for the analysis framework. This was linked with the Biggar Report's concern that there was not a clear understanding of the underlying problem or market failure.

4.3.2 The Biggar Report also questioned whether there was a coherent framework underlying the list of efficiency considerations.

4.3.3 As set out in 4.2.1, any proposal to amend the existing TPM must ultimately be progressed as a Code amendment and therefore comply with the CAPs. Also, Clause 3.4 of the Charter about Advisory Groups states that all Advisory Groups must adhere to the Authority's CAPs when making Code amendment recommendations. In addition, in the guidance from the Authority Board, July 2011, the Board noted (paragraph A16) that whilst TPAG should ensure the problems with the existing arrangements are articulated clearly, this must be within the context of the Authority's regulatory framework, including the CAPs.

4.3.4 In order that TPAG's analysis is relevant to the Authority's regulatory framework, TPAG considers it is entirely appropriate to use the CAPs as a basis for its analysis although, TPAG has, in section 3, set out a more expansive statement of the problem. This articulates TPAG's discussions in more detail and importantly gives more background on the underlying regulatory and market context for transmission pricing in New Zealand and describes the earlier analysis on possible problems in transmission pricing that underpins TPAG's work.

4.3.5 TPAG has also considered the Biggar Report's concerns that its efficiency considerations were ad hoc and not grounded in good public policy and has reviewed Biggar's alternative framework.

4.3.6 TPAG has reconsidered whether the efficiency considerations are appropriate but contests Biggar's view that the appropriate approach to public policy analysis should be to compare reality to a perfect world that does not exist. TPAG considers it is impossible to use Biggar's framework as it is too far removed from the reality of the New Zealand regulatory and market context when considering the TPM. It is also inconsistent with the legislative and institutional arrangements surrounding electricity regulation. Specifically, these require incremental decisions by regulators to seek improvements in efficiency.

4.3.7 The efficiency considerations were developed by TPAG recognising significant earlier work in Stage 1 and 2 of the Review, and evolved from earlier criteria advanced by Frontier Economics. Following the Biggar Report, TPAG reconsidered the efficiency considerations, both how they evolved from earlier analysis and how they compare with other transmission pricing criteria or principles advanced by other economists and alternative criteria advanced by Darryl Biggar in the Biggar Report.

4.3.8 In some cases alternative criteria are not required for evaluating transmission pricing in New Zealand. For example, full cost recovery for Transpower is an implicit assumption as the TPM Is an allocation methodology designed to recover Transpower's full economic costs.

4.3.9 While there are some differences between the criteria, it is more a matter of semantics rather than substance. Some of the criteria and principles overlap. TPAG's consideration of whether the efficiency considerations are ad hoc and not grounded in good public policy is set out in a TPAG paper on Efficiency Considerations, 8 August 2011[18].

4.4 Efficiency considerations

4.4.1 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.

4.4.2 The TPAG has found it helpful to develop a number of more specific efficiency considerations incorporating dynamic, productive and allocative efficiency[19] and exploring the particular

[18] Available at: http://www.ea.govt.nz/document/14583/download/our-work/advisory-working-groups/tpag/10Aug11/

[19] 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;

implications of these for transmission pricing. These considerations have provided a structure to assess the efficiency costs and benefits of different options. Table 8 summarises the TPAG 'efficiency considerations' for transmission pricing.

Table 8 Efficiency considerations

Consideration	Implication
1: Beneficiary pays	Apply a beneficiary pays approach: • where beneficiaries can be clearly identified and charges can be determined which do not exceed the beneficiaries' private benefits; • where the cost of identifying beneficiaries does not outweigh the benefits of doing so; 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	Maintain, or provide additional, location price signals if these promote more efficient: • coordination of investment and use of transmission, generation, and Demand Side Management (DSM); or • trade-offs between the costs and benefits of reliability.
3: Unintended efficiency impacts	Seek efficiency gains through: • minimising any incentives arising from the TPM that could distort economic dispatch or economic use of electricity; • minimising any incentives arising from the TPM that create generation, demand-side, 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 practice	Adopt an approach that: • is consistent between regulators; • is durable;

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

Consideration	Implication
	• 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.

4.4.3 These efficiency considerations are discussed further below.

4.5 Submitter and Biggar Report comment on specific efficiency considerations

4.5.1 Whilst a number of participants responded favourably to the efficiency considerations some raised the issues with the efficiency considerations such as that there was too little consideration of the rational willingness of beneficiaries to pay for an investment, the efficiency effects on consumers, the overall benefits to consumers and consumers ability to respond to altered pricing. The Biggar Report raised issues around the beneficiary pays consideration and the wealth transfer aspects of good regulatory practice. This section reflects TPAG's consideration of these issues. The Biggar Report also questions why there is no consideration that guarantees that the charges should cover the costs of Transpower, although this is not relevant in the New Zealand context as this is part of the role of the TPM.

Efficiency consideration 1: beneficiary pays

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

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

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

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

4.5.5 If the grid investment decision does not substantially rely on private information then charging beneficiaries is less likely to improve decision-making. Similarly charging parties who are not beneficiaries simply to get them to actively engage in the decision-making is unlikely to improve outcomes, since Transpower and the Commerce Commission are required to fully consult and already have access to external experts and advice to identify least cost options and to challenge and justify the investments under the investment test.

4.5.6 The Biggar Report suggested that there was unlikely to be a benefit from improved decision-making from allocating costs to beneficiaries as, provided the costs of an investment are allocated in a way that ensures that all parties gain or lose by a material amount they will have incentives to participate in the decision-making process. TPAG acknowledges there are some issues to consider in the application of beneficiary-pays in order to gain benefits from improved decision-making, and these are considered below.

4.5.7 <u>Benefits in terms of improved durability of the methodology.</u> Where beneficiaries can be clearly identified and are not charged more than they benefit, this can lead to improved durability of the methodology and improved regulatory certainty, through reduced disputes and interventions. There is a dynamic efficiency benefit as the stable regulatory environment where nobody pays more than their private benefit, will promote the complementary investment by load and generation that use the transmission system.

Issues with application of beneficiary pays

4.5.8 There are several issues to consider in applying a beneficiary-pays approach to allocating the cost of transmission assets:

a) **Identification of beneficiaries**. Applying a beneficiary-pays approach requires a robust method for identifying beneficiaries that can be applied consistently across the grid. The benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively and clearly identified. In an interconnected electricity network there can be practical issues that make identifying beneficiaries costly and open to dispute. Identification of beneficiaries is more difficult for economic investments, but for reliability investments, it is reasonably clear, since the investment is predicated on reduction in unserved energy, and the incidence of this reduction must have been determined. In a renewables system, reliability investments lie between load and firm generation

b) **Risks from over or under-allocating costs to beneficiaries**. If costs are either over or under allocated to beneficiaries there is the prospect that allocating costs to beneficiaries could contribute to poor investment decision-making rather than enhanced investment decision-making. For example, beneficiaries with over-allocated costs will incur costs from a new investment that exceed their private benefits and may have incentives to lobby against the new investment. Beneficiaries with under-allocated costs may have incentives to lobby for the new investment. Additionally, if the allocation of costs to beneficiaries is not robust, the consequent allocation by the regulator could be seen as arbitrary and may have a stifling effect on new investment.

c) **Alignment between decision-rights and allocation of costs:** Where a beneficiary pays approach is used the greatest value can be obtained by having it linked to investment decision-making. Ideally the beneficiaries would be identified prior to decisions being made, would have some decision-rights in the investment approval process, and the allocation of costs to beneficiaries would reflect the ex-ante value to those parties from the investment. Ideally the cost allocation to beneficiaries would also be 'fixed' at the time of each significant grid investment (i.e. not changed arbitrarily ex-post) and be structured so as to minimise any inefficiency in use of the new investment.

d) **Allocating sunk costs versus new investments**: Generally the beneficiary-pays approach is better applied before a new investment is approved, as this is when information about the prospective beneficiaries and their willingness to pay has the most impact on investment decisions. It is also the point at which beneficiaries are more likely to reveal their interests, especially if the regulator makes a credible threat that the investment will not occur otherwise. After an investment has been made, there is less value to be obtained in allocating sunk costs to beneficiaries, unless doing so impacts on future investment decisions, not only in transmission but in generation and load. One way this happens is that the allocation of sunk costs drives expectations about how sunk costs will be handled after the next investment. Information on the willingness of beneficiaries to pay will be generally harder to obtain once the investment is a sunk cost as all suspected beneficiaries are incentivised to avoid the costs. Assessing potential beneficiaries before an investment will involve controversial analysis, and the further into the future beneficiaries are being assessed the more is the need to rely on debateable views of future generation, consumption, and pricing. Ex-post allocation of sunk costs is by contrast done on the basis of data rather than projections of these variables, but has the drawbacks above. There is a trade-off to be made between a lower influence on investment and dynamic efficiency using actual data to allocate costs retrospectively, and a higher influence using projected information. But on balance a forward looking application of the beneficiary pays principle is generally to be preferred in circumstances where it is practical to implement.

e) **Free-riding:** In a commercial environment, it is not necessary to identify all beneficiaries and free-riding is only a problem if the sum total of the free-riders' ability to hold-out prevents welfare enhancing investments occurring. All that is required is that the full costs of an investment can be met by a subset of beneficiaries where their benefits exceed their costs. Similarly, in a centrally planned and regulated investment environment it is not necessary to identify all beneficiaries and free-riding is not a problem as free-riders cannot hold-out to delay welfare enhancing investments.

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

Efficiency consideration 2: locational price signalling

4.5.9 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.

4.5.10 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[20]. 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.

4.5.11 The RCPD interconnection cost allocation methodology is an attempt to provide additional price peak demand management signals in regions with growing net demand[21] requiring transmission 'reliability' investments.

4.5.12 The Stage 2 analysis of the benefits of locational signalling for economic transmission investments concluded that the costs of additional locational signalling of economic transmission investments are likely to outweigh the benefits. However, there may be gains in providing additional locational signalling for reliability-driven investments, SRC assets, or from maintaining the existing locational price signalling through the TPM.

Efficiency consideration 3: unintended efficiency impacts

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

4.5.14 It is important to note that these unintended efficiency impacts include efficiency impacts on demand-side, and that this is particularly the case for energy-intensive users.

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

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20 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.

21 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 4: Competitive neutrality

4.5.16 The TPM should, as a general rule, provide a level playing field for new investment in electricity generation, transmission and demand-side (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

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

Efficiency consideration 6: Good regulatory practice

4.5.18 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.

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

a) **Consistency between regulators**. Overlaps between the Authority and the Commerce Commission decision-making are coordinated and treated consistently.

b) **Durability.** Pricing outcomes that are arbitrary, subjective or ad-hoc must be avoided as they are likely to trigger interventions either through the regulator, courts or Ministerial direction.

c) **Consistency over time**. A principled, consistent approach is taken that over time accommodates changes in the use of and investment in the grid. This should reduce regulatory intervention, enable market participants to more easily predict future regulatory behaviour, and thereby minimise incentives for lobbying.

d) **Consistency over the whole grid**. A principled, consistent approach is taken for all grid assets for the same reasons as set out in (c).

e) **Wealth transfers and step changes in prices.** The TPM is kept reasonably stable and predictable in terms of outcomes for participants. Circumstances will change over time and this may require modifications to the TPM, but changes that result in wealth transfers must be justified by clear efficiency improvements. Any proposed change must be an effective, efficient and proportionate response to the issue concerned. Where change is justified then it must be well signalled in advance and a transition should be provided so that participants can have time to adjust.

f) **Market fit**. Any TPM is consistent with overall market design and likely market evolution.

5 HVDC cost allocation

5.1 Problem statement

5.1.1 The current TPM allocates HVDC costs to all grid-connected SI generators with an allocation proportional to peak (kW) generation based on HAMI. The HVDC charge is therefore an existing locational signal that may lead to inefficient pricing signals for both the short-term use of the network and for investment in generation and impacts on competition that may not be offset by reduced investment in the HVDC link. In brief, the HVDC charge may be resulting in the following problems:

a) **Possible generation investment inefficiency from delaying SI generation**. The HVDC charge leads to a disincentive for investment in SI generation relative to NI generation as the HVDC charge adds around 10% to the total cost of a new SI project. This disincentive would lead to generation investment inefficiency if SI generation investments are delayed relative to otherwise equivalent NI options .

b) **Competition effects between SI generators resulting from the HVDC charge** . The allocation mechanism for the HVDC costs would favour new generation investment in the SI by large incumbent SI generators relative to small incumbent generators or new entrants if those new investments by the large incumbent are more likely to delay alternative NI rather than SI investments by competitors. If this occurs it would lead to large incumbent SI generators increasing their dominance in the SI with a consequential reduction in competition in generation and retail, and potential inefficiency.

c) **Generation investment and dispatch inefficiencies from the HAMI price structure**. The HAMI allocation provides disincentives to generators to offer peak capacity and to invest in or maintain peaking generation capacity.

5.1.2 TPAG has investigated these three problems by assessing the following issues:

a) The investment inefficiency from delaying cheaper baseload SI options which could be accommodated over the next 25-30 years without requiring any addition HVDC investment (section 5.2).

b) The investment inefficiency arising from the HAMI pricing structure discouraging the offering of existing capacity and the development of new peaking investment in the SI (section 5.3).

c) The competitive detriment arising from the allocation mechanism providing an advantage to large incumbent SI generators (section 5.4).

d) The allocative gain or loss from reductions in SI new entry costs lowering wholesale prices offset by any increases in transmission charges resulting from a shift in cost recovery to customers (section 5.5).

e) The extent to which the allocation of HVDC costs to existing or new SI generators will affect future HVDC investment decisions under a regulated investment test (section 5.6).

5.2 Issue (a) generation investment inefficiency

5.2.1 To assess the generation investment inefficiency it is necessary to :

a) Determine the effective disincentive for each potential SI investor taking into account the impact of the current HVDC allocation method on the opportunity cost for new entrants and incumbents.

b) Assess the impact of this disincentive on the timing of new generation investments, taking into account the range of costs for new projects and the different scenarios that may emerge for key drivers such gas availability and cost, carbon pricing, resource consenting issues and electricity demand growth.

The effective charge and competition between SI generators

5.2.2 The average net HVDC cost under the existing TPM is expected to be $35/kW/yr in real 2011 dollar terms[22] for the 15 years following the commissioning of pole 3 if SI generators continue to receive the value of HVDC rentals.

5.2.3 While this $35/kW/yr HVDC cost represents the disincentive for new entrant generators in the South Island, incumbent generators may not suffer the same level of disincentive. This is because total HVDC charges are fixed and any new investment in SI generation will result in a reallocation of the charges between the incumbent generators and new generators. A completely independent new SI generator will see the full incremental HVDC cost for its new generation ($35/kW/yr), but all the incumbents will benefit from a reduction in their share of the costs. The extent to which large incumbent generators have an advantage relative to new entrants depends upon both its share of the HVDC costs and the investment 'counterfactual' which applies.

5.2.4 The Commission's Stage 2 consultation paper suggested that a large incumbent such as Meridian would have an effective HVDC charge of 30% (100% minus its existing 70% SI share of HVDC costs) of the full cost to new entrants[23]. However some submitters to the Stage 2 Consultation Paper suggested[24] that the Commission's analysis was incorrect and that all generators face the same marginal cost of increased capacity regardless of SI market share. This is because, provided that a similar investment would be made by a competitor in the SI, the incumbent would obtain the benefit of reduced HVDC charges on its existing generation regardless of whether it or a competitor built the new capacity in the SI.

5.2.5 TPAG concludes that both claims can be true, depending on assumptions about other investments that could be displaced by the new SI generation. If the new generation is assumed to displace another SI generation option on a one-for-one basis, then it is correct that all SI generators will face the same incremental cost (counterfactual 1). On the other hand, if the new generation does

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22 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.

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

24 See submission from RTANZ, and NZIER (section 2.2) available at: http://www.ea.govt.nz/document/11154/download/our-work/consultations/transmission/tpr-stage2options/submissions/

not have the effect of displacing other new SI generation (counterfactual 3), the Commission's analysis is correct, and large incumbent generators will have a significant advantage in new generation investment.

5.2.6 In practice one cannot be certain about what would occur in the absence of a new investment by one of the incumbent SI generators, and different incumbents are likely to make different judgements about what is likely and what their cost relative to a competitor's cost will be. For this reason TPAG considers that the most likely effective HVDC charge influencing investment decisions will be half way between these extremes (counterfactual 2).

Table 9 SI generation investment counterfactuals

Option	Description	Meridian's net incremental cost from HVDC charge
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%-69%)*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 counterfactual 2 it has been assumed that the cost impact is half way between the two extremes.	\$23/kW/yr

5.2.7 The generation investment inefficiency depends on which of those counterfactuals the incumbents use in their commercial decision-making and which projects they might be able to develop. In its submission NZIER suggested that Meridian should be able to develop all new SI projects at the same cost as any other developer and that the appropriate counterfactual was 3 (i.e. none of the projects that it developed would crowd out investment by others). On this basis, NZIER claimed that the investment inefficiency would be less than \$10m NPV.

5.2.8 However this is not a reasonable assumption for the following reasons:

- It is unrealistic to expect that Meridian would be able to develop projects such as hydro on the Clutha (where Contact has land and synergies with other plant on the same river chain), or projects such as Arnold, Wairau, and Mahinerangi where TrustPower has resource consents and land ownership agreements.
- It is unrealistic to expect that Meridian would have the interest or capability to develop all the SI opportunities as efficiently as the 'market' where a range of incumbents and new entrants are in full and equal competition.
- It is more realistic to expect that if Meridian were to develop all these options, Meridian would assume there was a high risk that investments by others in the SI would be crowded out or delayed. This would imply that Meridian would use an intermediate counterfactual (such as Counterfactual 2) in its investment decision-making.

5.2.9 TPAG accepts that the assumption used in the earlier analysis (Counterfactual 1) overstates the generation investment inefficiency, but notes that this was used as an alternative to separately assessing the competitive detriment of Meridian's competitive advantage. TPAG believes that a reasonable basis for assessing the generation investment inefficiency is Counterfactual 2 combined with an assumption that Meridian can develop 50% of the generic new SI projects (excluding Clutha Hydro, Arnold, Wairau and Mahinerangi stage 2). TPAG has revised its analysis to account for this and has separately addressed the competitive detriment arising.

Assessing the Impact on generation investment

5.2.10 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 (NPV) of new generation investments and an associated economic loss. There is some evidence that this is a real effect in that generators are only currently committing[25] to investing in the South Island where the schemes can be embedded and hence avoid the HVDC charge.

5.2.11 The increase in the NPV of new generation investment costs depends on how much lower cost SI generation is delayed by how many years. This will never be known with certainty, but it is easy to estimate bounds on this cost.

High level analysis to determine bounds on the generation investment inefficiency

5.2.12 It is possible to establish upper and lower bounds adopting a high level first principles analysis considering three assumptions:

- The quantity of additional new SI generation that might be delayed as a result of the HVDC cost allocation. This could be between zero and the limits imposed by the committed link. The latter can be approximated by SI demand plus the maximum link transfer minus existing SI generation. This will increase over time (with SI demand growth) but is approximately 5600 GWh from 2020. This would be more than enough to accommodate, say, 900-1200MW of wind or hydro at a 40% to 60% capacity factor (3548 to 4730 GWh/yr).
- The extent to which that SI new generation is cheaper than NI options which must be less than the effective HVDC charge. This means that the amount by which SI generation is cheaper than NI options must be in the range 0 to $35/kW/yr. A typical value might be in the range $10 to $20/kW/yr assuming Counterfactual 2 with Meridian undertaking 50% of the generic SI projects.
- The year from which the new SI generation could delayed, which depends on demand growth, retirements of existing plan and on the quantity of new NI generation which is cheaper than any of the SI options. If, for example there was 700MW of low cost geothermal, and the average demand growth rate was around 1.7% p.a. then T would 2019-23. This could be 2017-21 if there was only 500MW of very cheap geothermal.

5.2.13 Table 10 gives illustrative calculations of the increased NPV of investment for these assumptions.

[25] There are a number of grid connected projects that are being investigated (such as Meridian's 35MW hydro on the Pukaki discharge, and the Mahinerangi stage 2 wind farm development, but these have not been committed.

Table 10 Illustrative calculations of the potential generation investment inefficiency

Estimated upper bounds on generation investment inefficiency NPV $m									
GWh of relatively cheap SI supply	Max: 4730 GWh			High: 3548 GWh			High: 3548 GWh		
GWh of very cheap NI supply	High: 5519 GWh			Lower: 3942 GWh			High: 5519 GWh		
Initial year	Later: 2019-23			Early: 2017-21			Later: 2019-23		
Relative cost of SI to NI supply $/kW/yr	$30	$20	$10	$30	$20	$10	$30	$20	$10
NPV of additional investment cost $m	$149	$99	$50	$143	$95	$48	$119	$79	$40

Note: NPV to 2011 for 30yrs from 2012 at 9% real pre tax discount rate.

5.2.14 This high level analysis shows that there is a potential for up to $40 to $150m additional investment cost.

5.2.15 The lower bound on the generation inefficiency could be zero if:

- there is no new SI generation that is cheaper than NI options over the period; or
- there is a very large amount of very cheap new SI generation that can be built very early (despite the HVDC charge) and that this fully loads the HVDC link, excluding any other SI options.

Refined Analysis

5.2.16 In reality the actual investment cost impact will be between the extremes identified in the high level analysis above, because there is a mix of NI and SI options and their relative costs will depend on a range of factors such as:

- project capital and operating costs relating to resource quality, resource consents, connection costs; and
- fuel costs and constraints, carbon costs, exchange rates, heat rates for thermal options.

5.2.17 Many of these factors are inherently uncertain. It is possible to use estimates at a project level in combination with scenarios of exogenous factors to create a more realistic view of the relevant amounts and likely costs of new investment options.

5.2.18 TPAG refined the high level analysis above to account for these factors.

5.2.19 The refined analysis used a list of potential projects that was developed by the Commission for the statement of opportunities published in September 2010 and used by the Ministry of Economic Development in its Energy Outlook published in December 2010. The list has been developed over a number of years and has been consulted on and used in modelling work for transmission investments and other electricity sector issues.

5.2.20 The list of projects includes around 960MW of NI geothermal, 2900MW of NI wind and 1360MW of SI wind, 470MW of NI hydro and up to 2240MW of SI hydro, 310MW of NI cogeneration and 42MW of SI cogeneration. Much of the hydro is relatively high cost. It also includes a number of NI gas fired thermal options which may be viable if there is sufficient local gas available as a reasonable cost. Additional coal fired options are also possible based on SI, NI or imported resources and may be viable if coal prices and carbon prices are low enough, but this is not considered likely. The typical level of costs of these projects and the earliest commissioning has been updated to reflect more recent information. As discussed in section A.2.4 the analysis focuses on base load and renewable options as these are most likely to be significantly affected by the HVDC cost recovery.

5.2.21 Exchange rates are assumed to revert to long run averages, 0.6 for the USD:NZD cross rate and 0.5 for the Euro:NZD cross rate. With those assumptions, the typical real 2010 capital cost levels are assumed to be; $2300 to $2500/kW for wind, $3000 to $6000/kW for hydro, $4700 to $5200/kW for geothermal, $1750/kW for CCGTs and $3000/kW for coal. In addition to these generic costs the costs of connection[26] is included.

5.2.22 As discussed above, all these costs are still subject to considerable uncertainty. This is accounted for by randomly sampling project capital by ± 20% around a generic capital cost for each general class of investments (geothermal, wind, hydro, thermal etc). Random sampling is also a proxy for other variations in resource quality affecting the base-load equivalent value of the output, and for other more qualitative factors (such as portfolio factors, risk assessments, option valuations) affecting the relative ranking of projects by investors in the market.

5.2.23 In each scenario it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. Geothermal and hydro projects are subject to significant resource consent risks. This is accounted for by limiting the total MW of each type of technology available over the next 30 years.

5.2.24 In response to submissions on the Discussion Paper TPAG has updated its earlier analysis to reflect the key drivers underlying the 5 different scenarios used in the 2010 SOO. Those 5 scenarios are considered to be equally weighted. They include different carbon and gas price scenarios as well as different limits on geothermal and hydro development reflecting resource consenting issues. One of the scenarios assumes that Tiwai smelter is phased out in 2025, another assumes that there is additional gas discoveries sufficient to enable additional CCGTs to be built.

5.2.25 The refined analysis involved taking the cost information and ranking the different options in the same way that commercial decision makers would. The analysis focused on baseload and renewable options as these are the projects that are most likely to be affected by the HVDC charge. The mid merit thermal plant options are almost all in the NI and most of the pure peaking plant has a common cost and will most likely be developed in the NI despite the HVDC charge, as it will have a higher value there.

5.2.26 A common device for comparing and ranking baseload projects is to derive an equivalent long run marginal cost. This is essentially the average real time weighted price at a reference location that would be required to cover the investment costs over a project's life. It was necessary to use heuristics to put baseload, renewable and thermal projects on a common baseload basis. Those heuristics include factors to account for supply intermittency and variability (wind and hydro), peaking capability and value, regional marginal loss factors and reference capacity factors for

[26] This includes all uncommitted deep and shallow transmission costs necessary to accommodate these projects. It excludes committed capital expenditure such as the lower South Island facilitating renewables project.

thermal options. Heuristics of this nature are commonly used by commercial decision makers. They are based on a combination of historical experience and more detailed market modeling.

5.2.27 This more refined analysis is fully described in Appendix A the results of which are summarised in the table below.

Table 11 Generation Investment Inefficiency from HVDC charge (HAMI allocation)

Additional "baseload" investment cost $m NPV		
	With Rentals	Without Rentals
1. Sustainable Path	$22	$26
2. SI Wind	$23	$31
3. Med Renewables	$21	$25
4. Coal	$24	$35
5. High Gas Discovery	$31	$39
Average	**$24**	**$31**
Minimum	$10	$11
Maximum	$48	$66
Standard Deviation	$9	$11

Note: This is based on counterfactual 2 and assumes Meridian can develop 50% of generic SI projects.

5.2.28 The result of the analysis is a range of present value cost of $10m to $48m (mean $24m, standard deviation $9m) attributable to the HVDC charge if SI generators continue to receive HVDC rentals or between $11m and $66m (average $31m, standard deviation $15m) if they do not.

5.2.29 The lower end of the range applies in scenarios and sensitivities where there is a large quantity of NI generation options that have a lower cost than SI options and hence the HVDC cost allocation does not have a significant impact for a number of years. Note that in all cases it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. The lower levels of economic cost arise from there being a significant block of cheaper NI wind. Approximately twice as much potential wind is assumed to be available in the NI as in the SI and hence there is the potential for a delay in the impact of the HVDC charge if much of this NI resource is cheaper than the SI.

5.2.30 The upper range of economic cost applies in scenarios where there are some SI options which are of a similar or lower cost to NI options and hence the HVDC cost allocation results in a much more significant delay in the development of these lower cost SI options from an earlier date, and SI generators no longer receive HVDC rentals. This can also occur in the scenario where it is assumed that there is sufficient local gas supply available for additional CCGT projects in the NI in the 2020s that have a similar cost to NI and SI options. In this case an HVDC charge could delay cheaper SI options by many years and hence result in a higher present value cost.

Significance of the analysis

5.2.31 The Biggar report and a number of submitters have questioned the significance or materiality of the estimated generation inefficiency, particularly given that Commission's Stage 2 analysis described the benefits from enhanced locational price signals as immaterial.

5.2.32 TPAG noted in the Discussion Paper that the Commission's Stage 2 analysis derived a mean upper bound estimate of the national benefit of $14m NPV from enhanced locational price signals. This was an upper bound because it identified the potential difference in national benefit from perfect co-optimisation of generation and transmission, relative to perfect optimisation of generation while ignoring transmission costs.

5.2.33 In practice it would be extremely difficult to design a location-based transmission pricing arrangement that provided perfect price signals to generators about the cost of transmission. In particular, the tilted postage stamp, augmented nodal pricing, and load flow based allocation methodologies were unlikely to achieve this outcome, and the benefits would be less than the upper bound estimate of $13.5m. TPAG observed that it would be difficult to justify the additional transaction cost to introduce locational price signals when the upper bound of benefits was so small. In other words, TPAG concluded that it was not confident that the benefits of the change outweighed the costs of implementing the change.

5.2.34 In the case of the HVDC options, the situation is different. Even in the context of the total generation build (of $7-8 billion), it is not correct to conclude that the estimated assessed benefits are insignificant or within the margin of error. The object of the assessment is not to accurately establish the present value of future investment or to even establish a future that is more likely than not to occur. The purpose of determining a supply curve for new investment is to establish a credible timeline for investments distributed between the North and South Islands. The analysis focuses only on impact that the HVDC charge has on the relative timing of projects directly affected given a credible timeline in a given scenario.

5.2.35 TPAG's analysis suggests that, under a credible range of build scenarios, changing the HVDC charge could affect the timing of generation build sufficiently to give a present value range between $0 to 150m. With further analysis, TPAG has identified a more likely range of $24±$9m.

5.2.36 For decision-making, the level and uncertainty of this potential generation efficiency gain (ie, $24±9m) should be compared to the costs of implementation, and the potential impact on new HVDC investments under the investment test to be established by the Commerce Commission under Part 4 of the Commerce Act. Understanding the size and risk of the resulting net benefit is critical to any decision to change the TPM.

Limitations in the refined analysis and robustness testing

5.2.37 A number of submitters and the Biggar Report pointed out the limitations of the refined high level analysis and questioned the robustness of the results.

5.2.38 TPAG acknowledges that there are some limitations with the refined high level analysis including the following:

- The analysis focuses only on the timing of new baseload and renewable options rather than the full mix of mid-merit, peaking and baseload. There will be tradeoffs between existing thermal generation (e.g. retirement, refurbishment or change in role) and new generation, thus the economic demand for base load investments could be greater or less than assumed.
- The analysis does not model the operation of the full system and hence has to rely on heuristics to account for factors such as peaking factors and marginal loss factors to enable thermal, geothermal, wind and hydro options to be ranked on a baseload equivalent basis.
- While extensive sensitivity analysis is used, the analysis is deterministic in the sense that in each scenario it is assumed that projects are developed in order of lowest cost.
- The approach is not suited to more complex scenarios, such as rising gas and carbon prices, gas discoveries, new technologies etc.
- There may be other factors influencing the commercial timing of new investment in each island other than cost (portfolio effects, option values etc), although this is often difficult to model as it involves very subjective estimates of the level and correlation of future risks.
- The approach does not directly model spot price formation so the impact on wholesale prices needs to be inferred by the cost of new entry of different types in different regions.

5.2.39 Some of these limitations can be addressed using more complex models, for example the Authority's GEM central cost minimising model, a full market simulation model which includes participant bidding behaviour and hydro simulation or a stochastic optimisation model.

5.2.40 While these much more complex models can address some of these limitations, it is not clear that they would be able to reduce the inherent uncertainty in the estimated impact significantly and they each have their own limitations as outlined below.

- The GEM model can model the full system to a degree, but it still involves significant simplifying assumptions and it is a central planning cost minimising which does not necessarily reflect commercial decisions in the real market. Earlier analysis carried out as part of Stage 2 of the impact of the HVDC charge using GEM showed a similar order of magnitude $6-36m NPV.
- Full market simulation models require a set of behavioural assumptions (such as bidding strategies and new investment rules) which can significantly affect the outcomes. In most of these models it is necessary to make the assumption that new investment occurs when expected net revenues from spot prices rise sufficiently to cover the life time capital and operating costs. This is the same assumption used in the simplified analysis.
- Stochastic optimisation requires assumptions concerning the variations, correlation and evolution in the future uncertainties. These are very difficult to estimate and justify and it is not clear that these considerations would change the relative ranking of NI and SI options significantly.

5.2.41 TPAG has done some additional analysis to assess the sensitivity of the results to the heuristics and approximations employed as discussed in A.11. This shows that the results are reasonably robust to reasonable variations in the heuristics used. TPAG has also tested the robustness of the results to alternative assumptions regarding the effective HVDC charge to incumbents (i.e. the counterfactual). The results given in A.9 show those alternative assumptions could lead to variations of +$7m to -$9m in the estimated average generation investment inefficiency.

5.2.42 TPAG has also assessed the impact of additional considerations (such as consideration of commercial strategy and portfolio effects) which may mean that projects are not developed in strict cost order. The analysis is described in section A.12 and shows that reasonable levels of disorder may increase the standard deviation of the assessed generation investment inefficiency but that the level of disorder does not significantly affect the average.

5.2.43 The analysis used by TPAG was developed, in part, to address concerns raised by submitters in Stage 2 of the review that the GEM model was a complex cost minimising black box, which did not necessarily reflect investment decision-making in the market. However, submissions on the Discussion Paper have raised concerns that the analysis is too simplified.

5.2.44 In response, TPAG has asked the Electricity Authority to update the earlier GEM analysis. This analysis is in progress but the results are not yet available. While TPAG recommends that this work is, completed, TPAG does not expect that the update of the GEM analysis will significantly differ from the results of the simplified analysis, but might help to cross check and refine some of the assumptions used in the simplified analysis.

5.2.45 TPAG was not able to cross check the results using full market simulation or stochastic optimisation, however both of these approaches have their own limitations and it is not clear that they would significantly narrow the inherent range of uncertainty arising from the major factors which has already been accounted for in the analysis and which are matters of policy or judgment (such continued receipt of rentals, the counterfactual, uncertain project costs and uncertain future external factors such as gas prices and availability, carbon prices, demand).

5.2.46 TPAG believes that additional modeling is unlikely to reduce the uncertainties.

5.3 Issue (b): Generation investment and dispatch inefficiencies from the HAMI price structure

5.3.1 The HAMI price structure may provide incentives to:

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

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

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

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

5.3.2 Under the HAMI cost allocation, grid-connected SI generators face a very high initial cost when they offer peak generation above their highest previous injection, since they will incur HVDC charges for the following 5 years if it is dispatched. Although they will get the benefit of dispatching peak generation up to this level for the following 5 years at no further additional cost, they will be uncertain if these benefits will outweigh the costs. This feature of the HVDC charging structure tends to make generators reluctant to offer peaking capacity even when the value is relatively high. Some generators report they are withholding over 100MW of peaking capacity in the SI as a result[27]. It is noted that this capacity is available for grid emergencies as Transpower has agreed not to adjust generators' HAMI in these situations, but it is not being made available at other times.

[27] See page 28 of the Stage 2 Consultation Paper.

5.3.3 The withholding of capacity can lead to dispatch inefficiencies, which the Commission estimated to be towards the lower end of a $0-100m range[28]. TPAG considers that the dispatch inefficiency is more likely to be in the range $0-$5m NPV and probably at the lower end of this range.

5.3.4 One reason that SI generators may be withholding capacity from the market may be owing to constraints on the HVDC limiting the transfer, and therefore value, of SI peaking capacity. It is likely that much of this withheld capacity would be returned to the market once the marginal value of SI peaking increases after pole 3 is commissioned. There might still be some incentive to withhold relatively uncontrolled run-of-river capacity, although this is unlikely to be very significant. The influence of HVDC firm capacity on the value of SI peaking generation is considered in more detail in Appendix A, section A.15.

5.3.5 In addition to the dispatch inefficiency there is potential generation investment inefficiency from discouraging new peaking capacity in the South Island which is estimated to have an economic cost in the range $0-31m NPV[29]. TPAG's analysis is summarised in Table 12.This investment inefficiency depends on there being up to 200MW of additional peak capacity available from either upgrading existing hydro capacity or from modifying the design of new generation to provide additional peaking capability, which is up to $23-35/kW/yr cheaper than NI peak capacity options. Given the uncertainties around this estimate, TPAG considers that the expected value is likely to be well below the midpoint of this range at, $8±8m NPV.

Table 12 Potential peaking generation inefficiency from the HAMI allocation methodology

HVDC Rentals	Net HVDC cost	Withholding existing peaking capacity	Peaking investment inefficiency (200MW)
		Economic Cost (NPV $m)	
SI generators continue to get HVDC rentals	$23-35/kW/yr	$0 to $5m Immaterial	Range $0 to $31m Expected $8±8m
SI generators don't get HVDC rentals	$25-40/kW/yr	$0 to $5m Immaterial	Range $0 to $35m Expected $9±9m

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

5.4 Issue (c): Competitive detriment from the competitive advantage to Meridian

5.4.1 The estimates of the generation investment inefficiency are based on Meridian having a relative advantage in developing new SI projects compared with its competitors. The estimates assume Meridian uses counterfactual 2 in its SI investment decision-making. This assumes an effective

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

[29] See section A.15.

$23/kW/yr HVDC opportunity cost compared with $35/kW/yr for new entrants. This means Meridian has $9 to $12/kW/yr advantage relative to new entrants or its smaller incumbent competitors, and equates to a $3 to $4/MWh advantage for typical SI wind and hydro projects.

5.4.2 This assumption that Meridian uses counterfactual 2 lowers the generation investment inefficiency (since Meridian's projects will not be delayed as much), but gives rise to potential competitive detriment. This arises from:

- Meridian undertaking more SI projects and gaining a higher market share than otherwise; and
- Meridian facing less competitive pressure, with potential implications for contract prices in the SI and for productive and investment execution efficiency.

5.4.3 The analysis provided in Appendix A (at section A.14) indicates that removal of the HVDC cost allocation to new entrant SI generators is likely to lead to the following competitive benefits over the next 30 years:

- new SI generation options would compete on an equal basis with NI options, rather than suffering an $8-10/MWh disadvantage;
- Meridian would no longer get a $3-4/MWh advantage over its competitors in the SI;
- other SI incumbents and new entrants can compete equally with Meridian for all new SI generation options and as a result Meridian's market share in the SI is likely to fall around 3-5% more than that expected in the status quo.

5.4.4 It is difficult to estimate the allocative and productive impacts of these effects, however there are some benchmarks:

- Anticipated economic gain from increased competition resulting from the transfer of Tekapo (which reduced Meridian's SI capacity share by 5-6%) must have exceeded the estimated cost of $4-30m. A further 3-5% reduction in Meridian's SI market share might deliver some portion of this implied benefit[30].
- It is difficult to estimate the impact of increased competition from new entrants on a large incumbent's productive and investment execution efficiency. However it is very likely that the combination of increased competition from other incumbents and new entrants in the SI and the likely lowering of SI wholesale prices will put pressure on Meridian to cut costs and improve its performance. Even a very small improvement in performance can give rise to significant productivity gains. For example a 2% improvement in Meridian's investment execution efficiency for 220MW in 2020 and a $0.04/MWh (0.2%) reduction in operating costs[31] would result in a $10m NPV productive efficiency gain.

[30] Note that although the package of reforms was aimed at increasing retail competition, this could have been achieved through the virtual asset swaps and so the additional cost of the physical asset transfer must have been justified on the basis of benefits from increased wholesale competition. Not all of this implied benefit can be attributed a reduction in Meridian's market share in this case. This is because the transfer of Tekapo to Genesis also involved the transfer of control of a significant portion of SI hydro storage to a competitor as well as a reduction in market share.

[31] Note that the cost benefit analysis of the proposal to introduce an FTR market to manage locational risk included an assessment of the productivity gains arising from increased competition between NI and SI generators. In this analysis the assessed price impact was between $0.36 and $0.71/MWh and the assessed productivity impact (from generators operating more efficiently to retain margins) was 50% of this level ($0.18 to $0.36/MWh). See "Managing locational price risk: Proposed

5.4.5 Given the two considerations above, TPAG considers it is realistic to estimate the productive and investment execution efficiency gain from removing the competitive advantage to Meridian arising from current HVDC cost allocation methodology to be $10m ± 5m NPV.

5.5 Issue (d): Allocative efficiency gains or losses from price effects

5.5.1 To assess the allocative efficiency gains or losses it is necessary to assess how any increase in transmission charges to customers resulting from a reallocation of HVDC charges is offset by the flow on impact of a reduction of $8-10/MWh in SI new generation costs into wholesale prices in the SI and NI.

5.5.2 A number of submitters on the Discussion Paper have raised concerns that this reduction in new entry costs in the SI may not flow through to customers. TPAG has addressed the arguments and evidence for this pass through and further considered the impacts on prices in section 5.9.

5.5.3 In summary, the analysis in section 5.9 shows that:

- Although the evidence is not conclusive, SI wholesale contract prices may fall by $2-6/MWh in the medium term as the LRMC of SI options needed to avoid the risk of NI to SI price separation as a result of conservative hydro management in dry year is lowered by $8-10/MWh.
- Both NI and SI contract prices may fall by around $3/MWh beyond 2020 once the cheaper NI geothermal options are developed and NI and SI options are more comparable.

5.5.4 Section A.14.33 in Appendix A shows that the allocative gains from net price reductions in the NI and the SI over the next 25 years could be between -$0.1 to +$5.6m NPV, depending on the HVDC pricing option, if there is a medium term reduction in SI wholesale prices as discussed above.

5.5.5 If there is no additional medium term wholesale price reduction in the SI then the allocative gain is likely to be between -$0.3 to +$2.0m NPV.

5.5.6 A number of submissions suggested that the TPAG analysis did not adequately consider the demand-side ability to adapt to altered pricing, does not model deadweight losses from increased electricity prices or does not account for the efficiency effects on customers. The estimated allocative losses and gains do account for these impacts. However in the absence of wealth transfers, these gains or losses are small in relation to the other generation investment inefficiency costs.

5.6 Issue (e): Impact on future HVDC investment costs

5.6.1 TPAG notes that the HVDC pole 3 upgrade is now committed. Any investment efficiency benefits from continuing the HVDC cost allocation to new SI generation will relate to any further HVDC investments. Future investments in the HVDC link, apart from a possible second cable for pole 3, are probably 20-30 years in the future.

5.6.2 It is difficult to quantify the possible impact on future HVDC investment costs from a change in the TPM which removes the HVDC charge on new SI generation because it involves subjective judgements about:

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amendments to Code", April 2011, pages 86 and 87. The illustrative productivity gain used in this calculation is only 10 to 20% of the assessed gain from increased competition arising from the FTR contract market.

a) how robust the centrally determined investment decision-making process (under the investment test determined by the Commerce Commission under Part 4 of the Commerce Act) would be with a change in the TPM;

b) how the incentives applying to, and the capability of, the various parties engaging in the decision-making process for a new HVDC investment may change as a result of a change in the TPM; and

c) the extent to which the decision-making process is enhanced by continuing the current TPM and might create value by modifying HVDC investment decisions.

5.6.3 TPAG recognises that this is a potentially complex and contentious issue which will need to be assessed for each TPM option that is considered. This is discussed further in section 5.10.4 below but the efficiency of future economic investments in the HVDC need not be significantly affected given that any expansion will need to be demonstrated to provide a national NPV benefit under the Commerce Commission's investment test.

5.7 Conclusion on the problems

5.7.1 This section has discussed and concluded that:

- there is a disincentive for new grid-connected generation in the SI relative to NI which will leads to generation investment inefficiencies of between \$10m and \$48m NPV (expected \$24±9m[32] NPV) given the assumptions made in the analysis);
- there is a risk that a lack of competitive neutrality between large SI incumbents and new SI entrants, could lead to productive and investment execution inefficiencies of around \$10±5m;
- there could be -\$0.3 to +\$5.6m[33] allocative gains from net reductions in wholesale prices in the NI and SI arising from the reduction in SI new entry costs flowing through;
- the HAMI allocation discourages investment in new grid-connected peaking capacity in the SI resulting in the risk of an investment inefficiency of up to \$31m NPV, but is more likely to be at the lower end of this range at \$8±8m NPV;
- the HAMI allocation encourages the withholding of grid-connected SI peaking capacity from the market resulting in the risk of a dispatch inefficiency of up to \$5m NPV but is more likely to be insignificant; and
- the efficiency of future economic investments in the HVDC need not be significantly affected given that any expansion will need to be demonstrated to provide a national NPV benefit under the Commerce Commission's investment test.

5.7.2 To be consistent with the Authority's statutory objective the TPM must be consistent with promoting competition in, reliable supply by, and the efficient operation of, the electricity industry and for the long term benefit of consumers. Changes to the status quo should be contemplated if there are potential efficiency gains available.

5.7.3 There was no universal agreement amongst the TPAG members on the materiality of the efficiency gains, and the possible impact on future HVDC expansion decision, but the TPAG

[32] This is a more likely one standard deviation range.

[33] These depend on the assumed medium term impact on SI wholesale prices and the HVDC option.

concludes that there is sufficient evidence of potential efficiency gains to warrant analysis of alternative TPM options.

5.8 Options to address the problems

5.8.1 The Stage 2 Consultation Paper proposed three possible alternatives to the status quo: a MWh allocation to SI generators; a postage-stamped allocation to all load, generation or a mix of load and generation; and an 'incentive-free' allocation to existing SI generators; and considered a further capacity rights option (proposed by NZIER). The Stage 2 HVDC options were intended to remedy the inefficiencies identified during Stage 2 and further investigated by TPAG.

5.8.2 TPAG has assessed the Stage 2 options along with a further transitional option developed by TPAG. The options are described in Table 13.

5.8.3 For each of these options there are a number of variants, some of which were suggested by submitters on the Stage 2 Consultation Paper. TPAG has not assessed all of the variants against its efficiency criteria.

Table 13 HVDC Stage 2 Options assessed by the TPAG relative to the status quo

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

Option	Description	Rationale for Change
transition	existing grid-connected SI generating stations.	prices and wealth transfers.

5.8.4 Whilst capacity rights would involve major market redesign which is outside the scope of TPAG's role, TPAG has considered the costs and benefits of capacity rights in order to compare with other options.

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

Variants of the HVDC capacity rights options

5.8.6 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[34] 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 14.

Table 14 Capacity rights options

	NZIER Proposal	Merchant Link Proposal
Overseas model	None that the TPAG is aware of.	Australian market interconnector regime[35].
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.	Additional secondary trading may occur if there is a demand, but is not required.
Market clearing	Requires a 2 solve process[36] to identify	SPD needs to be modified to include link

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

[35] 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.

	NZIER Proposal	Merchant Link Proposal
and Settlement	'users'[37] of the HVDC, and integration of separate spot trading regime. Energy and reserve prices will be affected.	offers, but otherwise it is co-optimised and settled as now. Energy and reserve prices will be affected.

Variants of the MWh option

5.8.7 In submissions to the Stage 2 consultation, 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.

5.8.8 The issues associated with these variants are discussed in the Table 15.

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

[37] Although it may be possible to identify 'users' of the HVDC using this 2 solve approach, it would be much more difficult to identify all the possible 'beneficiaries' and it would be very costly to require that all these parties actively trade link rights to match

Table 15 MWh Allocation Variants

	Option for assessment: allocate to SI generators on MWh shares over several years	Variant: allocate to SI generators/NI load for S->N flows and to SI customers/NI generators for N->S flows.
Competition issues and generation investment inefficiency	Avoids SI peaking inefficiency, and reduces generation investment inefficiency, but may introduce dispatch inefficiencies which could become significant if there was SI thermal generation[38].	Would avoid SI peaking inefficiency and further reduce generation investment inefficiency, but may introduce other dispatch inefficiencies.
Impact on end-user costs	None.	Difficult to predict the net impact of flow varying customer transmission costs and flow on impacts of the cost allocation to generators on wholesale prices in each island.
Long run impact on end-user costs	May be small positive impact from slightly lower LRMC in SI.	Difficult to predict net effect of customer transmission charges and flow on impact on LRMC and Short Run Marginal Cost (SRMC) on wholesale prices.
Consistency across grid	Same as status quo.	Similar to Status quo but a more complex sharing arrangement.
Consistency over time	Only a minor change to status quo.	Significant change to status quo, and likely to be unstable over time because of variations in hydro inflows.

5.8.9 The alternative MWh allocation methodology described in Table 15 which involves a more complex allocation between NI/SI load and generation on the basis of relative shares of South->North and North->South flows has not been treated as a full separate option. This is because the allocation to SI generators would achieve the main efficiency gain with respect to peaking generation inefficiency with a lower risk of other dispatch distortions and with no price impacts on end users.

Variants of the postage stamp options

5.8.10 The potential generation investment inefficiency can be avoided if new SI generation is not required to pay HVDC charges through postage stamping of HVDC charges. There are several options to implement postage stamping. For example HVDC charges could be included with other interconnection assets and recovered from customers through existing RCPD charges or they could be recovered via a MWh charge on all generators, or via a mix of MWh charges on all generators and all customers. The economic impacts and the impacts on end-user costs of these alternatives are expected to be similar (see Table 16), so they have not been treated as separate options for the purpose of this analysis.

[38] If there was a SI thermal plant a MWh charge to SI generators may lead to more expensive NI thermal plan being dispatched ahead of it. This would be inefficient.

Table 16 Postage stamp allocation variants

	Option for assessment: allocate to offtake via interconnection charge	Variant: allocate to all generation on MWh	Variant: allocate 50% to all offtake and 50% to all generation on MWh
Competition issues and generation investment inefficiency	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.	Avoids peaking and other generation investment inefficiency as there is no disincentive of SI versus NI investment.
Initial impact on end-user costs	$3/MWh increase in average transmission costs[39].	$3/MWh immediate increase in wholesale prices as additional variable cost to all generators flows through.	$1.5/MWh increase in transmission charges and $1.5/MWh increase in wholesale prices.
Long run impact on end-user costs	$3/MWh transmission cost increase offset by flow on impact of around $10/MWh reduction in SI LRMC relative to NI.	$3/MWh increase in wholesale offset by flow on impact of around $10/MWh reduction in SI LRMC relative to NI.	$3/MWh increase in wholesale and transmission costs offset by flow on impact of around $10/MWh reduction in SI LRMC relative to NI.
Consistency across grid	Consistent treatment of interconnection assets.	Differing treatment of interconnection assets.	Differing treatment of interconnection assets.
Consistency over time	Significant change on implementation but consistent over time.	Significant change on implementation but consistent over time.	Significant change on implementation but consistent over time.

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

5.8.12 An alternative transitional option was raised in submissions on the Discussion Paper. This involved a phased allocation of HVDC costs to all generators rather than to distributors. This option is expected to have a similar efficiency impact as the transition options discussed below. This is because, in a competitive market, a common cost allocation to all New Zealand generators is expected to flow directly through to wholesale prices.

Transition to postage stamping the HVDC charge

5.8.13 The objectives of a transition to postage stamping would be to avoid the short term step changes in prices to consumers that would occur under a change to postage stamping the HVDC costs,

[39] 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.

while at the same time maintaining any efficiency benefits resulting from a postage stamp approach and providing a net-benefit to consumers.

5.8.14 Under a transition to postage stamping, existing grid-connected SI generation would be required to pay for a portion of the HVDC charges which could be phased out over a transitional period. Ideally the allocation between existing grid-connected SI generators over the transitional period would be fixed in advance so as to remove any incentives that could distort behaviour and create inefficiencies. This could be done, for example, on the basis of historical share of HVDC charges, allocated to specific generating stations.

5.8.15 The allocation of costs to existing grid-connected SI generation stations and the length of the transition can be chosen to avoid step changes in prices, allocative inefficiencies and value transfers. The length of transition can also be set so as to make an 'incentive free' allocation workable. In addition the transitional arrangements can accommodate the value impact to the SI generators of no longer receiving the HVDC rentals so as to avoid competition issues arising from existing SI generators being recipients of the proceeds of FTR auctions in which they participate.

5.8.16 There is a range of different transition options, each with a different level of allocation of HVDC costs and a different transition duration and phasing.

Table 17 Postage stamp transition variants

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

5.8.17 The postage stamp transition options are discussed in more detail in Appendix B.

'Incentive free'

5.8.18 In response to submissions from NZIER, MEUG, Norske Skog and others, more information is provided on the possible design of an 'incentive free' allocation. 'Incentive free' allocation is also discussed in more detail in Appendix C.

5.9 Impact of options on customer prices – Does a reduction in new entrant costs flow through to customers?

5.9.1 This section discusses the potential impact of the HVDC options on wholesale prices in the SI and the NI. It considers submitters' concerns that reduced costs of new entry in the SI may not flow through to customers.

Theoretical basis for new entry costs flowing through to wholesale prices

5.9.2 Removal of HVDC charges on new SI generation will reduce SI new entrant costs by around $8-11/MWh for typical wind or hydro projects.

5.9.3 While this may not have an immediate impact on spot prices[40] it is likely to flow through into SI and New Zealand forward contract prices and into future spot prices as the level and timing of new investment (and incumbent behaviour) adjusts to a new equilibrium.

5.9.4 With demand growth (or plant retirement) spot prices can be expected to increase over time. When they are high enough, competitive new entrants will invest at such a level that, following entry, spot and contract prices are sufficient to cover their expected operating and fuel costs and provide a return on the capital invested. The actual outcomes in the spot market following entry will vary as a result of demand, hydrology variations etc. But new entrants can contract to reduce their exposure to these fluctuations. If there is too much entry, or if demand growth falls, then expected spot and contract prices will fall again and new entry will be deferred until extra demand growth (or plant retirements) causes the expected spot and contract prices to rise again.

5.9.5 Where there is weak competition in the spot market, large incumbents may have (from time to time) the capability to withhold capacity or price up their capacity to increase spot prices in the short run. While this strategy may be profitable in the short run (depending on the incumbent's contract level), it can quickly become counterproductive if prices are held up so high that this triggers premature entry by competitors, as this leads to incumbents simply losing market share and having to withhold greater and greater capacity from the spot market to maintain higher prices. Incumbents cannot easily prevent new entry and large customers have second order incentives to contract with new entrants or small competitors to enter earlier or at a larger scale in this situation. A more profitable strategy for a large incumbent is to withhold or price up so that spot and contract prices just approach the cost of new entrants, so as to avoid triggering new entry until it is required to meet demand growth[41].

[40] Since, as several submitters have observed, the HVDC HAMI charge is not a direct component of the short run marginal cost of the price setting generators.

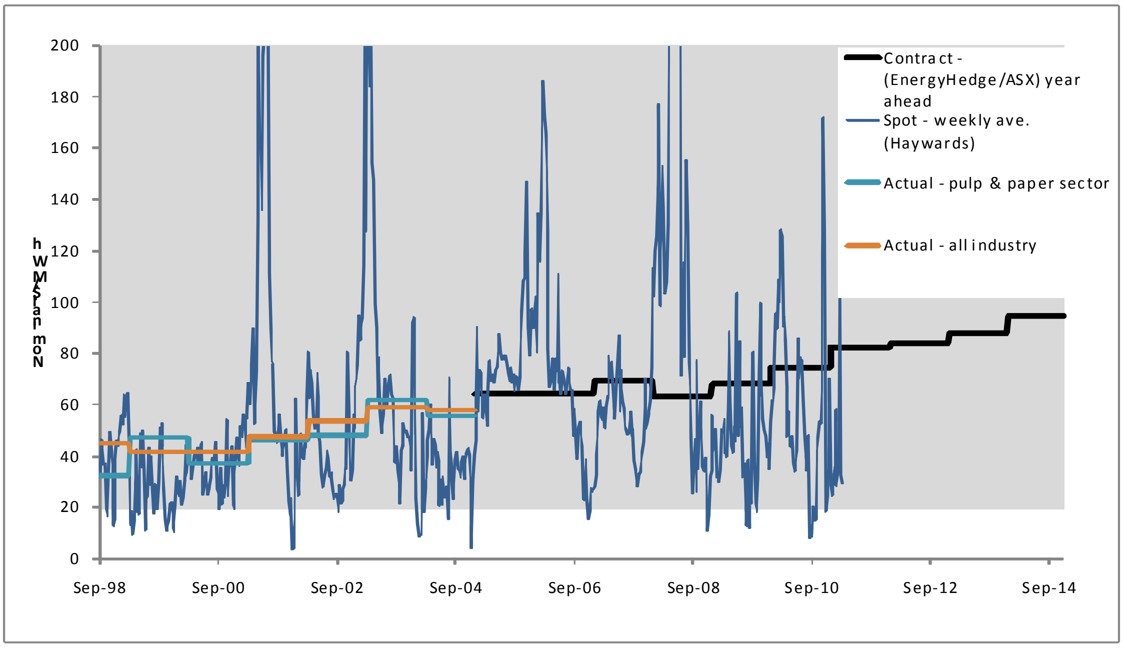
[41] Note that because new entrants have sunk costs, it is possible that contract prices may be held a margin above new entrant costs, however this does not mean that a certain reduction in new entrant LRMCs won't be reflected though to a reduction in forward contract prices. Similarly in a market with rising long run marginal costs it is possible that entrants may enter slightly

5.9.6 In workably competitive oligopoly markets this competitive dynamic often reflects in forward contract prices (i.e. contract prices beyond the influences of short term random fluctuation in inflows or supply and demand) bumping up to the cost of new entry. More competitive markets tend to show periods of lower contract prices whenever there is a relative surplus of supply over demand.

Evidence in the New Zealand market

5.9.7 This effect cannot be readily observed in spot prices as in New Zealand these are dominated by inflows and the fluctuations in hydro storage as illustrated in Figure 1. New entrants will be aware that these price fluctuations are temporary and will instead focus on year ahead (and beyond) contract prices which will capture the expected level of spot prices averaged over all possible inflows.

Figure 1 Spot and Forward Contract Prices



Source: Electricity Authority contract database and central database and MED Annual Electricity Statistics.

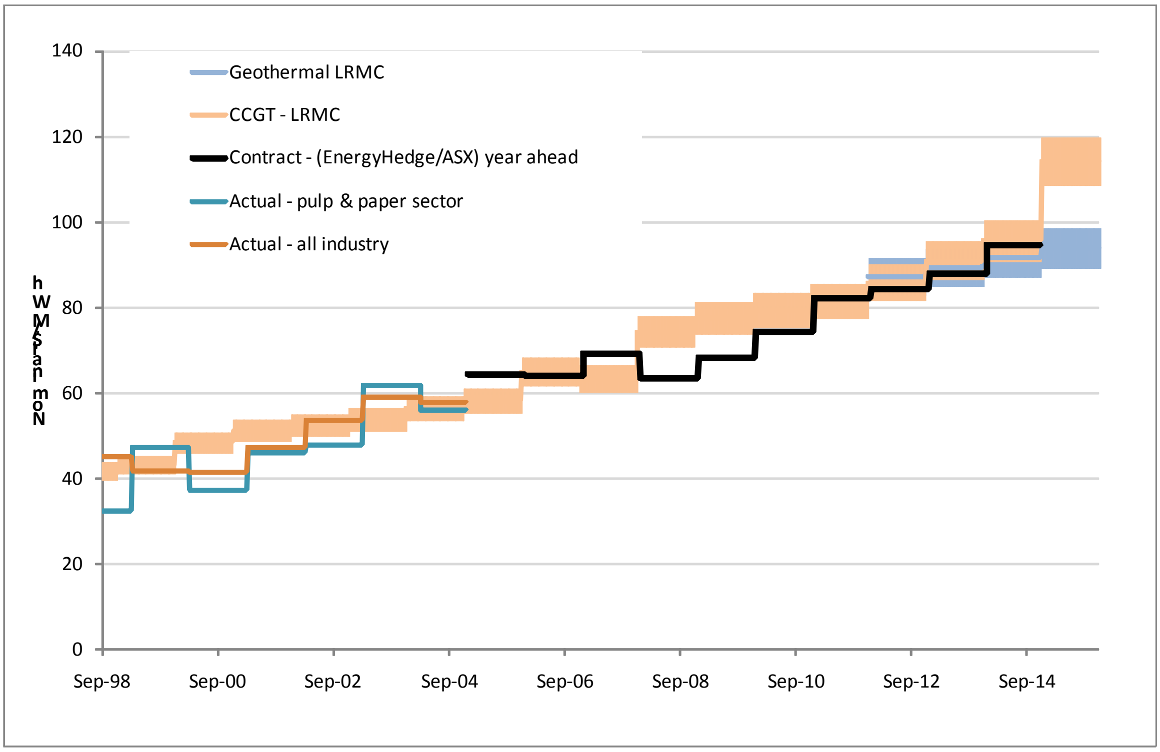
5.9.8 Figure 2 below shows the relationship between year-ahead contract prices and estimates of the LRMC of a new CCGT based on capital costs, exchange rates, fuel costs etc as they applied in each year. The CCGT LRMC was chosen as this reflected the lowest cost new entry option over the period to 2007.

5.9.9 This shows a broad correlation between contract price and LRMC. There is some evidence that contract prices have fallen somewhat below LRMC in the 2008-2011 period as a result of lower than expected demand growth resulting from the economic recession and reduced demand at the Tiwai smelter. This is indicative of a workably competitive oligopoly market. Note that the chart also includes the forward ASX contract prices out to 2014 which align with both geothermal or

earlier than indicated by its simple LRMC (since it expects higher revenue later), however this does not mean that a reduction in LRMC won't flow through to contract and future spot prices.

CCGT new entry costs. CCGT new entry costs are of limited relevance now as expected increasing gas and carbon prices make geothermal the more competitive option.

Figure 2 Year ahead contract prices and estimates of LRMC



Source: Electricity Authority contract database and estimates of CCGT LRMC from "Issues Paper – Survey of Market Performance – Market Design Review, Electricity Commission, 2007" updated to include new information from 2008.

5.9.10 The long run competitive dynamic described above means that a reduction in the cost of new entry is expected to flow into wholesale contract and future spot prices.

5.9.11 Some submitters suggested that the potential flow through of a reduction in LRMC to wholesale prices is likely to be low in a market where market power is exercised by generators in times of tight winter supply or transmission constraint. The theory would suggest the opposite as in this situation prices are likely to be held up to an entry-limiting level at all times, and so any reduction in the cost of new entry is likely to flow much more quickly than in a more competitive market. Also in this case, the incumbents are likely to adjust their bidding strategies to keep expected spot and contract prices up to the level which reflects the cost of independent new entry which may well be greater than its own new entry cost. This means that the price impact is more likely to reflect the full $8-11/MWh level of the HVDC charge rather than the lower effective rate for the large incumbents. For this reason the size and speed of a flow through of any reduction in LRMC arising from removal of the HVDC charge on new entrants could be greater than TPAG has estimated.

Potential differential impact in the South Island

5.9.12 It is only SI new entry prices that are influenced by the HVDC charge and hence it is necessary to look at the balance of supply and demand and competition between each island. There will be many situations where there is an effective national competitive market. However when constraints on the HVDC bind, the markets can separate and prices can diverge. Pole 3 reduces the risk of constraints significantly (particularly from South to North), however there still remains a risk of North to South constraints[42] in dry years. This risk can be mitigated through conservative hydro storage management, but this increases the probability and duration of NI to SI HVDC transfer during drier than normal years and the risks of significant inter island price separation. This can cause SI contract prices to continue to rise above NI prices until they are sufficient to justify a minimum level of SI generation investment[43] to offset the SI demand growth.

5.9.13 This issue is not captured in the simplified LRMC modelling as the modelling does not account for the hydrological variability and the increasing risks of dry year price separation if there is no new SI generation investment to match demand growth.

5.9.14 In submissions TrustPower suggested that this may lead to existing HVDC charges already being factored into SI forward contract prices, and hence a reduction in the SI new entrant cost may flow through into SI prices much earlier than the Discussion Paper analysis suggested.

5.9.15 TPAG has explored this issue and notes that there is some evidence of this effect:

- ASX forward contracts for Benmore in 2013-14[44] are higher than those at Otahuhu as shown in Figure 3; and
- modelling carried out by Energy Link in March 2011[45] shows the same feature, see Figure 4.That work simulated the operation of the market over a full set of hydrology and accounted for bidding rules used to manage hydro storage and constraints in the AC and HVDC system in wet and dry years. The modelling showed that, absent a minimum level of SI new generation investment, the dry year risks rise and as a result SI expected spot prices exceed Otahuhu levels from 2014 until 2024.

5.9.16 The minimum level of SI generation necessary to avoid significant price separation is likely to be relatively small. However it is unlikely to emerge in a commercial market unless SI wholesale contract prices are at a level to justify it. This means that a lowering of SI new entry costs may flow relatively quickly into SI prices, even in the period when SI new projects are more costly than NI options.

5.9.17 Once SI generation options become more competitive with NI options (i.e. once most of the relatively cheap geothermal is fully developed) it is likely there will be sufficient SI investment to substantially reduce the risk of significant price separation in dry years, and contract prices in both islands are likely to move together (separated by marginal loss factors only) and reflect the cheapest new entry cost in the New Zealand market overall.

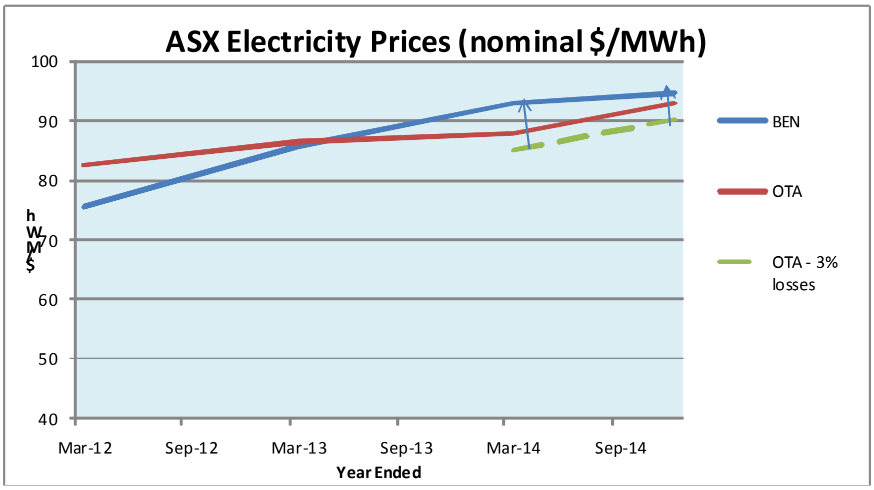
42 Either across the HVDC, or more likely, through the lower North Island HVAC system.

43 Either by bringing forward some wind or by building thermal hydro firming plant.

44 Note that these longer term contracts have limited liquidity and so their reliability is not as great as shorter term contracts.

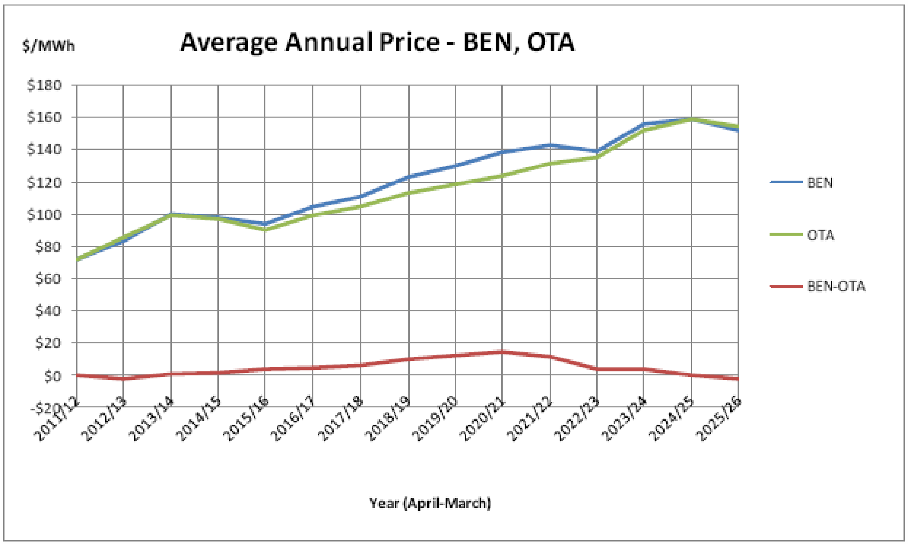
45 See “Losses and Constraints Excess Projections”, Prepared by Energy Link for the Electricity Authority, March 2011. This work was carried out for the Locational Price Risk Management project. See Figures 11, 24 and 27.

Figure 3 ASX Forward Prices



Source: Electricity Authority contract database.

Figure 4 Energy Link Analysis

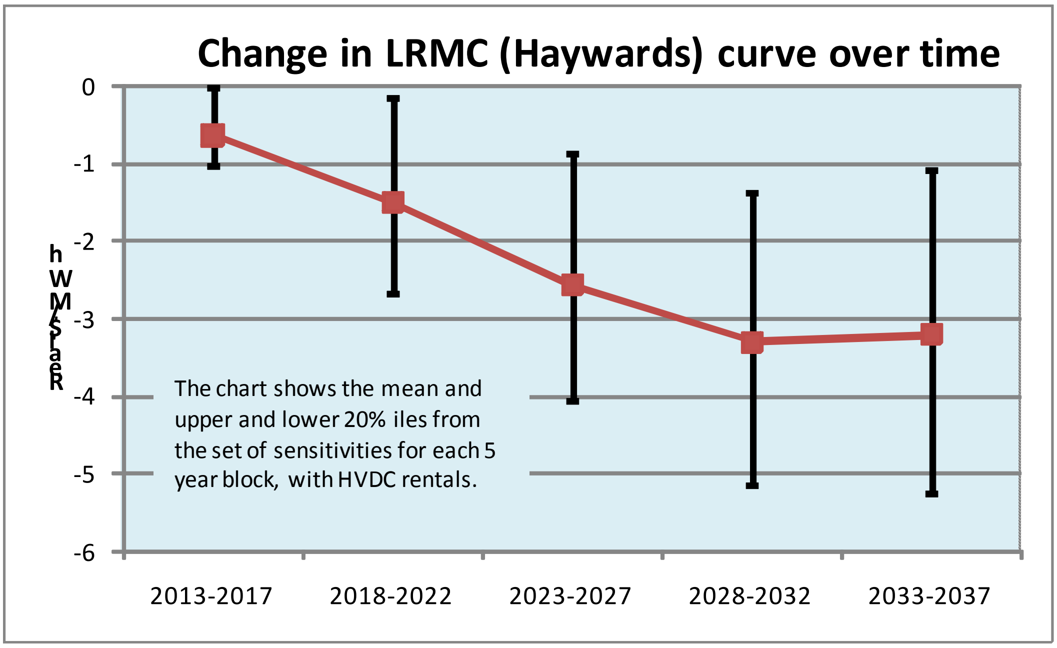


Source : Figure 24 in "Losses and Constraints Excess Projections", Energy Link March 2011.

Impact on NI wholesale contract prices

5.9.18 The NI 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 (referenced to Haywards) resulting from removal of HVDC charges on new SI generation. These estimates are derived by recording the LRMC impact from 110 sensitivities (including the 5 scenarios and 20 randomly selected sets of individual project capital costs).

Figure 5 Impact of Removal of HVDC charges on the NI LRMC Curve



5.9.19 As can be seen, the impact on 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.

5.9.20 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.

5.9.21 The present value average impact on the LRMC has a mean of approximately -$1.4/MWh and a standard deviation of around $0.4/MWh.

Impact on SI wholesale contract prices

5.9.22 As discussed above there is some evidence that a reduction in SI new entry costs may have an early impact on SI wholesale prices if, with SI demand growth, some minimum level of SI new investment is required during the period 2014 to 2022 to reduce the risk of north to south inter island transmission constraints binding in dry years. If this is the case then a reduction in SI new generation costs of $8-10/MWh is likely to have a significant and much earlier impact on SI wholesale contract prices.

5.9.23 The evidence for this is not conclusive, and even if this is an issue it is difficult to know what the impact on SI prices might be.

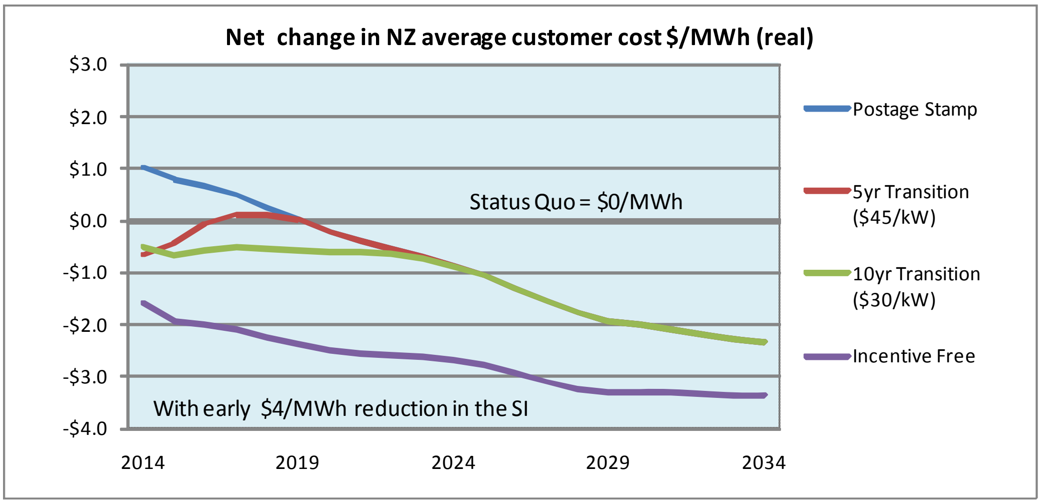
5.9.24 In light of this uncertainty TPAG has explored the implications of a scenario with a possible $2 to $6/MWh impact on average SI prices during the period to 2023. Beyond this period the reductions in SI wholesale prices should follow the reduction expected in the NI once there is more balanced pattern of NI and SI new generation development which ensures that the risks of significant north to south constraints occurring in dry years is reduced.

5.9.25 If this additional early reduction in wholesale prices is included then the present value average impact in the SI could have a mean of -$3.4/MWh. Without this the impact is likely to be the same as -$1.4/MWh expected in the NI.

Net Impact after accounting for impact of reallocated HVDC costs

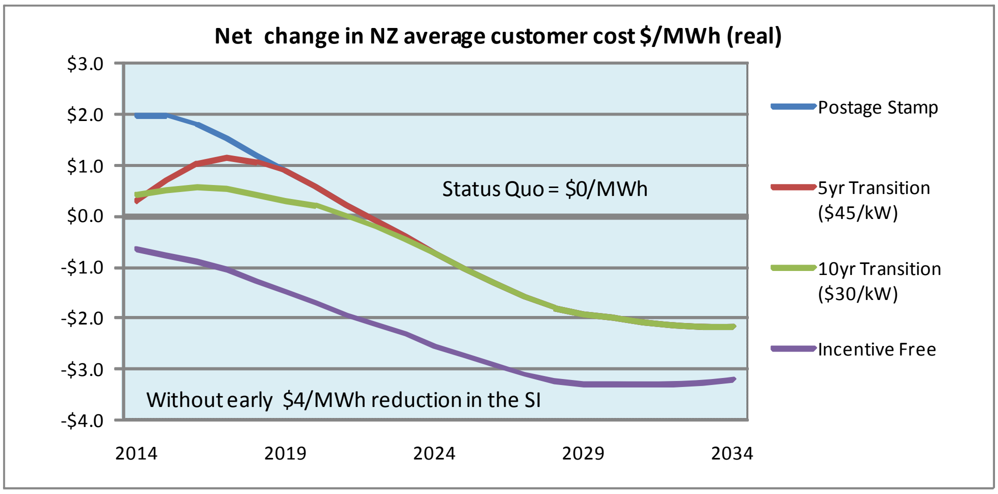
5.9.26 Additional HVDC costs reallocated to customers will offset the reduction in wholesale prices described above. The level and timing of this offset will vary depending on the HVDC option chosen. The full postage stamp option will have a $3/MWh increase from the start and the ‘incentive free’ allocation will have no increase at all. Postage stamp transitions will have a range of different profiles between these extremes.

Figure 6 Expected net impact on New Zealand average delivered prices – with an early reduction in SI prices



5.9.27 Figure 6 above shows the expected profiles for the net impact on New Zealand average delivered prices under a range of different options. With an early $4/MWh reduction in SI prices both the 10 year and ‘incentive free’ options provide net reductions in delivered prices to customers over the whole period. The full postage stamp and 5 year transition do not deliver significant reductions until 2022. Figure 7 below shows that if there is no early price impact in the SI, then the 10 year postage stamp transition may not provide net reductions until 2022.

Figure 7 Expected net impact on average delivered prices – without an early reduction in SI prices



5.9.28 This issue of wholesale price pass-through has very little impact on the estimates of net efficiency gain, as the allocative gains or losses arising from the expected net price impacts are only of the order -0.3 to +3.4m, compared with generation investment inefficiencies in the tens of millions. However the issue is relevant to the assessment of wealth transfers which is relevant to the good regulatory practice efficiency consideration.

5.9.29 The estimated value impact on customers based on the price impacts above is provided in Table 18 below.

Table 18 Estimated NPV value impact of net price changes on customers

	Postage Stamp	Transition			'Incentive –free'
Initial SI Generator Charge ($/kW/yr)		**$45**	**$30**	**$30**	
Length of Transition (yrs)	**0 yr**	**5yr**	**10yr**	**15 yr**	**25 yr**
Additional net transmission cost ($m NPV)	$1,204	$814	$785	$662	$0
Wholesale price reduction($m NPV)					
Without early SI price impact	$952	$952	$952	$952	$952
With early SI price impact	$1,297	$1,297	$1,297	$1,297	$1,297
Net gain to customers ($m NPV)					
Without early SI price impact	-$253	$138	$167	$289	$952
With early SI price impact	$93	$483	$513	$635	$1,297
Net gain to customers $/MWh (PV avg)					
Without early SI price impact	-$0.5	$0.3	$0.3	$0.5	$1.7
With early SI price impact	$0.2	$0.9	$0.9	$1.2	$2.4

Notes: The NPV is calculated using a 9% pre-tax real over 25 years (to align with 'incentive free' term). Transmission costs are net of HVDC rentals (approx $192m NPV).

5.9.30 This analysis suggests that, in an NPV sense, customers as a group are likely to be better off by several hundred million under the postage stamp transition options, particularly if there is an early impact on SI wholesale prices. They are likely to be significantly better off under the 'incentive free' option as they get the full benefits of reduced wholesale prices without any significant increase in transmission charges The longer term transition options provide a small expected net gain to customers, but it is debatable whether this is sufficient to compensate for the risk that LRMC reductions may not fully flow through to wholesale prices.

5.9.31 Although the estimated NPV impacts on customers are large, these are a result of very small expected changes in net prices (of the order of $1/MWh, or less than 1% of delivered electricity prices).

5.9.32 Notwithstanding the theoretical arguments and empirical evidence on the flow through of reductions in LRMC to prices presented above, there remains a difference of views within TPAG as to the certainty and extent of potential wholesale price reductions arising from a $8-10/MWh lowering of SI new generation costs.

5.10 Assessment of options against efficiency considerations

5.10.1 This section applies the efficiency considerations set out in section 4.4 to each option relative to the status quo.

Efficiency consideration 1: Beneficiary pays

5.10.2 As set out in section 4.4, where beneficiaries and shares of costs can be readily identified, there are two possible benefits from applying a beneficiary-pays approach to the allocation of transmission costs:

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

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

5.10.3 However, there are several issues to consider in applying a beneficiary pays approach to allocating the costs of transmission assets.

5.10.4 This section:

a) considers issues in applying the beneficiary pays approach to the allocation of HVDC costs;

b) considers the possible benefits from applying a beneficiary pays approach to the allocation of HVDC costs; and

c) assesses the extent to which the options apply a beneficiary-pays approach compared with the status quo.

Issues in applying a beneficiary pays approach to the HVDC costs

5.10.5 Section 4.4 identified issues that would need to be considered in applying a beneficiary pays approach. These are summarised briefly in Table 19.

Table 19 Issues with application of beneficiary pays approach

Issue	Brief description
Identifying beneficiaries	It is important to apply the beneficiary-pays approach consistently across the grid and that beneficiaries can be clearly and objectively identified.
Risks from over or under allocating costs	Over or under allocating costs to beneficiaries risks contributes to poor decision-making.
Decision rights	Ideally allocation of costs to beneficiaries should be linked to decision rights.

Issue	Brief description
Sunk costs	Allocating sunk costs to beneficiaries will not improve decision-making if no future investments planned in near term.
Free-riding	This is not relevant while HVDC grid investments are centrally planned and subject to a regulatory test; the costs can be met by a subset of beneficiaries if their private benefits exceed the costs (ie they should be rationally willing to pay).
Potential distortions	It is important to avoid unintended negative efficiency impacts from the cost allocation.

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

Identifying beneficiaries

5.10.6 Under current arrangements the HVDC costs are allocated to grid-connected SI generators, while the AC interconnection costs are allocated to offtake customers. The application of a beneficiary pays approach was one of the many considerations, driven by the application of the pricing principles, in the Commission's decision on who should pay for the existing and any new investment in the HVDC link. The Commission, in the explanatory paper for its final decision on HVDC pricing methodology (March 2006) considered that beneficiaries of the HVDC link were widespread but not all beneficiaries would face strong incentives (or be able) to identify least cost investment options if they were paying for new and replacement investments in the HVDC link. This consideration stemmed from its interpretation of Rule 2.2 of section IV of Part F[46]. Rule 2.2, along with the other pricing principles, has been removed from the Code.

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

Using a regulated approach to determining beneficiaries

5.10.8 A beneficiary assessment was not applied when pole 3 was approved[47] under section III of part F of the former Rules. 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 for pole 3 replacing pole 1, relative to the case where pole 1 was retired.

46 "2.2 the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;"

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

5.10.9 The HVDC link provides a mix of benefits that varies according to time frame and circumstance. For example it primarily benefits[48]:

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.

5.10.10 The benefits arising in these different circumstances depend not only on the direction and magnitude of the power flows, but also on the prices in each island. For example, there may be many periods of relatively low flow across the HVDC link when price differences and hence benefits are low, while a significant percentage of the total benefit may arise in a much smaller number of periods when price levels and price differences are very high (e.g. very dry years or periods of capacity constraint).

5.10.11 The relative size of these benefits depends on a range of external factors that influence the merit order of new generation options (e.g. capital cost, exchange rates, resource availability, resource consents, international oil, gas and coal prices, local fuel supply and cost, new technology, and carbon prices). For example:

a) If there is a significant amount of geothermal capacity available at a lower cost than SI renewable options, or if there is a major NI gas discovery and low carbon prices, and SI demand continues to grow, then the balance of benefits will progressively move from SI generators/NI customers to SI customers (who will benefit from access to cheaper NI generation and dry year backup).

b) In a world where thermal options are not competitive with renewable as a result of high carbon prices and restricted local coal and gas supply, the HVDC link can allow a balanced development of renewables taking advantage of diversity in both investment costs and operational requirements (for example, wind flows and hydro inflows). The benefits of this are likely to be shared between the different groups.

c) If carbon prices are very high and local gas supply becomes very restricted then existing NI thermal generators may be retired. These could be replaced by renewable options and, depending on the relative availability and cost of renewable options in each island, the HVDC link can provide benefits, by providing access to the cheapest alternative in either island, sometimes in the South and sometimes in the North (it is difficult to know which, as most renewable options are limited by resources and the costs are relatively site, rather than island, specific). In this case the diversity value of having access to peaking capacity in either island is likely to increase as the percentage of wind on the system increases.

d) If there is a significant and sudden loss of demand in the SI then the HVDC link will provide benefits to SI generators/NI customers until a new equilibrium is established.

[48] 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.

5.10.12 Apportioning benefits between groups would require judgements on the nature and probability of these different states of the world. These judgements are likely to be subjective and debateable.

5.10.13 Further, the replacement of pole 1 by pole 3 provides a number of additional system benefits relating to reserves, security, losses, and competition, for which it is difficult to identify particular beneficiaries. For example:

a) The replacement of pole 1 with pole 3 retains the existing bi-pole operation and this has significant advantages over a monopole operation. The reserve requirements with a monopole are significantly greater (one pole can help cover the risk of failure of the other and losses are significantly lower). Also a bi-pole configuration increases the flexibility of system operations to deal with other high impact, low probability, events that could occur elsewhere in the electricity supply system. This will improve the overall reliability of supply.

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

5.10.14 TPAG members did not reach a consensus view on whether it is possible to clearly identify the beneficiaries of the HVDC link, with two views divergent emerging.

5.10.15 One view is that the considerations above mean beneficiaries are likely to change over time and objective identification of specific beneficiaries of the pole 3 upgrade may be difficult and problematic. The second view is that it is possible to identify that the SI generators are the primary beneficiaries; other participants may derive some benefits at different times, but these are insufficient to argue that they should pay for the HVDC.

HVDC capacity rights as means to identify beneficiaries

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

5.10.17 Table 14 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[49]). This approach does not require ‘users’ or ‘beneficiaries’ of the HVDC to be identified each trading period.

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

5.10.19 Proponents of the capacity rights options point to a key benefit of the arrangement as being the identification of the beneficiaries of, and recovery of the costs for, the HVDC link through a market-based process[50]. They contend that it would provide a more transparent identification of

[49] See “NZIER Capacity Rights Proposal – Implementation Issues”, Electricity Authority 30 November 2010.

[50] Whether beneficiaries of the link are identified and pay the cost of the link depends on some extent on the capacity rights model used. The NZIER approach identifies ‘users’ rather than beneficiaries.

beneficiaries and lead to less dispute and uncertainty about who should be funding the costs associated with the HVDC link.

Risks from over or under allocating costs to beneficiaries

5.10.20 Paragraphs 5.10.9 to 5.10.19 identified that any future investment in the HVDC link provides a mix of benefits to SI generators, SI customers, NI generators, and NI customers, and that allocating the benefits in an objective manner is difficult and problematic. As a result there is a high risk that some beneficiaries could be under-allocated cost and some beneficiaries could be over-allocated costs. If this is the case, there is the prospect that allocating costs to beneficiaries could contribute to poor investment decision-making rather than enhanced investment decision-making (for HVDC link investments).

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

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

Alignment between decisions rights and allocation of costs

5.10.23 Section 4.4 pointed out that, ideally, the beneficiaries of any investment in the HVDC link would be identified prior to any decisions being made; and they would have some decision-rights in the investment approval process. Under current arrangements investment decisions in respect of the HVDC link are made through a regulated process and beneficiaries have rights to make submissions, but not rights in respect of decision-making.

Sunk costs

5.10.24 TPAG notes that the HVDC pole 3 upgrade is now committed. Any investment efficiency benefits from applying a beneficiary pays approach will relate to any further HVDC investments. Future investments in the HVDC link, apart from a possible second cable for pole 3, are probably 20-30 years in the future.

5.10.25 In the short term the investment efficiency benefits from applying a beneficiary pays approach to HVDC allocation are likely to be relatively small.

Quantifying possible efficiency gains from beneficiary-pays

5.10.26 It is difficult to quantify the possible benefits from the application of a beneficiary pays approach to the HVDC link because it involves subjective judgements about:

a) how robust the investment decision-making process would be without beneficiary-pays;

b) the incentives applying to, and the capability of, the various beneficiaries of the HVDC transmission engaging in the decision-making process because of the application of a beneficiary pays approach; and

c) the extent to which the decision-making process enhanced by a beneficiary pays approach might create value by modifying HVDC investments decisions.

5.10.27 Nevertheless, it is helpful to consider some possible examples that might apply to the HVDC link. The following examples are an attempt to identify the minimum level of efficiency gains necessary to achieve NPVs resulting from the application of a beneficiary pays approach in the order of +$41±13m [51]. Some possible examples are:

a) A reduction in investment costs of $65m to $300m (15% to 70% of a possible $450m replacement of pole 2) in 25 years time is equivalent to $10-$40m NPV in 2011 at a 8% real pre tax discount rate.

b) Efficiency gains in the range of $10-$40m NPV could be achieved if the optimal timing of investment in a second undersea cable costing $125m[52] was varied 2 years from 2019 to 2021, or 14 years from 2019 to 2032 as a result of more accurate information on the extent and cost of existing SI generation peak upgrade options. Note that the calculation used to illustrate this is simply the value from deferring the capital expenditure. This is an upper bound on the net benefit as any delay in such an investment will be offset by the loss of benefits from an earlier commissioning. As a general rule the net costs of moving away from an optimal timing will follow a 'bath-tub' curve, which may be relatively flat for small variations around the optimum. If this was the case the upper bounds estimated here could be significant over-estimates.

5.10.28 Achieving a $10m NPV gain would seem possible provided parties paying are beneficiaries and are not charged more than the value obtained. Achieving $40m NPV seems implausible as it implies that access to better private information would result in a 70% lower cost for a pole 2 replacement or greater than a 15 year movement in the optimal timing for an additional undersea cable.

5.10.29 It is important to recognise that, if the beneficiaries are not correctly identified, or the costs are allocated in a manner that fails to reflect the value to the beneficiaries, then outcomes could be worse and potentially net negative under a beneficiary-pays approach. In this case investment might be too small or too late, resulting in costs of the same order of magnitude as the benefits.

5.10.30 The benefits from a more durable HVDC pricing methodology are also difficult to quantify. However, if beneficiaries can be robustly and objectively identified in a way that is cost-effective, there could be reduced disputes or interventions, leading to lower on-going costs to participants. On the other hand, the analysis in paragraphs 5.10.9 to 5.10.19 suggests that identification of beneficiaries is complex and likely to be subject to on-going controversy. Similarly, it is difficult to quantify the benefits from the greater certainty that may result from the application of a beneficiary-pays approach.

Assessment of the options relative to the status quo

5.10.31 Assessing the merits of the various HVDC cost allocation options against the beneficiary-pays approach, relative to the status quo, is a matter of judgement, and the TPAG members have made different judgements about the issues raised in this section.

5.10.32 The status quo allocates the HVDC costs entirely to the grid-connected SI generation stations. While the TPAG members agree that SI generators are one of the beneficiary groups, there are varying views on whether other beneficiary groups should be allocated HVDC costs and whether

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51 The range of generation investment inefficiencies identified in Table 29.

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

the allocation to the SI generation stations leads to investment efficiency gains through participation in investment decision-making. Although SI generators may have incentives to participate strongly in the investment decision-making process, they may not have incentives to seek the most efficient solution for the long term benefit of consumers.

5.10.33 Table 20 assesses whether each option applies a beneficiary pays approach and how each option compares with the status quo.

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

Option	Application of the beneficiary pays approach, assessment relative to status quo
HVDC capacity rights	Capacity rights should more clearly and objectively identify beneficiaries compared to the status quo, resulting in reduced likelihood of disputes, although the NZIER approach involves identification of 'users' and is more likely to discover those that benefit from constraining the link rather than the beneficiaries of an open access transmission system.
MWh allocation	The MWh allocation retains the allocation to grid-connected SI generation stations. Application of the beneficiary pays approach therefore has the same strengths and weaknesses as the status quo. Grid-connected SI generators retain incentives to be involved in the investment planning process but durability may be a problem, and they may have incentives to delay investments past the point at which it is economic to do so if their costs exceed the private benefit.
Postage stamp	The postage stamp option, by design, smears costs across customers and so does not apply a beneficiary pays approach except in the broadest of senses. It is unclear whether this option improves decision-making as different end-users face different incentives to provide accurate information to the decision makers. There may be an ongoing prospect for disputes (as in the status quo).
Postage stamp transition	The application of the beneficiary pays approach for this option is similar to the postage stamp option in respect to improved decision-making.
Incentive-free allocation to SI generators	The incentive-free allocation to SI generators retains the charge on existing grid-connected SI generation, but removes it from new generation. This has a similar impact on future decision-making as the postage stamp option, although it creates uncertainty as to how costs may be allocated following new investments. The allocation of all costs to just one subset of the beneficiaries might be viewed as arbitrary (i.e. not based on a principled and consistent approach) and those costs may exceed the value of private benefits. The different treatment of existing and new generation may lead to increased disputes and additional uncertainty for market participants which may reduce their confidence to invest in the market.

Efficiency consideration 2: Locational price signalling

5.10.34 Locational price signalling can promote more efficient coordination of investment in and use of transmission, generation and DSM or more efficient tradeoffs between the costs and benefits of reliability as set out in section 4.

5.10.35 The Stage 2 analysis of the benefits of locational signalling for economic transmission investments concluded that additional locational signalling of economic transmission investments is not justified.

5.10.36 The current HVDC cost allocation provides an additional locational signal which discourages new SI investment in favour of NI investment in the period following pole 3, even though such SI investment can be readily accommodated within the link capacity.

5.10.37 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 $10m and $48m NPV (expected $24±9m) over the next 30 years.

5.10.38 The MWh allocation to SI generators maintains the current locational price signal. The postage stamp, postage stamp transition and 'incentive free' options remove the locational signal. The capacity rights option would build in a different but potentially more refined locational signal.

5.10.39 Table 21 compares the locational signal provided by the options with that of the status quo. The case for maintaining the signal depends on whether the costs in terms of generation investment inefficiencies can be offset by the benefits of locational price signalling.

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

	Assessment relative to status quo
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 the TPAG as the analysis would be complex and is outside the scope of TPAG's role.
MWh allocation	Maintains the status quo locational signal to SI generation, but the signal is more favourable towards investment in, and dispatch of, peaking generation than the HAMI-based cost allocation.
'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

5.10.40 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; and

d) allocative efficiency impacts.

5.10.41 Sections 5.2 and 5.3 considered evidence of the first three of these inefficiencies in the status quo TPM.

5.10.42 The analysis set out in section 5.2 enabled the TPAG to conclude that there was sufficient evidence of potential efficiency gains from alternative options to warrant further analysis of these options.

5.10.43 The postage stamp, postage stamp transition and 'incentive free' options would entirely avoid the generation investment, peaker investment and dispatch inefficiencies associated with the status quo. The MWh option would avoid the peaker investment and dispatch inefficiencies and some portion of the generation investment inefficiencies associated with the status quo, but may introduce other dispatch inefficiencies associated with a MWh pricing structure.

5.10.44 Table 23, which summarises the TPAG's assessment of the options against the unintended efficiency impacts consideration, draws on the sections 5.2 and 5.3 analysis for the generation and peaker investment efficiency impacts and dispatch efficiency impacts for the postage stamp, postage stamp transition and 'incentive free' options. It also draws on the analysis for the peaker investment and dispatch efficiency impacts for the MWh option.

5.10.45 TPAG has undertaken some further analysis for this section in order to assess the generation investment efficiency impacts for the MWh allocation and the allocative efficiency impacts for all four of these HVDC options. It has not considered the unintended efficiency impacts for capacity rights in detail as this would be significantly more complex.

Generation investment efficiency analysis for MWh allocation

5.10.46 The investment inefficiency analysis with respect to the status quo has been repeated using a MWh allocation to SI generators[53] and is also set out in Appendix A, section A.7. The results are summarised in Table 22 which confirms that the economic inefficiency is likely to be lower with HVDC costs allocated to SI generators on the basis of a per MWh charge rather than HAMI.

Table 22 Generation Investment Inefficiency of HAMI and MWh HVDC charges

HVDC rental allocation	HVDC cost allocation and net incremental cost	Economic cost NPV $m
SI generators continue to get HVDC rentals	**$35/kW/yr HAMI**	$10-48m (expected $24±9m)
	$7/MWh	$3-40m (expected $17±6m)
SI generators do not get HVDC rentals	**$40/kW HAMI**	$11-66m (expected $31±11m)
	$8/MWh	$7-41m (expected $21±6m)

53 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.

5.10.47 The analysis suggests that the potential generation investment inefficiency would fall by around $7m to $10m on average, if the existing HVDC charge remained on grid-connected SI generators but was allocated proportionately to generation in MWh rather than HAMI.

5.10.48 Although a MWh allocation to SI generators would reduce the generation investment inefficiency, an inefficiency of between $3m and $40m (average $17±6m) would remain if SI generators continue to receive HVDC rentals and between $7m and $41m (average $21±6m) if they do not.

Allocative efficiency

5.10.49 If the HVDC costs were postage stamped to offtake customers, then RCPD transmission prices to those customers would increase by $24/kW. Offtake customers would receive HVDC rentals (or potentially FTR residuals). End-use customers would likely see an average increase in delivered energy prices of approximately $3/MWh[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].

5.10.50 The price increase from postage stamping HVDC charges to customers would be immediate and certain, but should be offset by a fall in wholesale prices in the medium term, as market prices adapt to a $4-11/MWh drop in SI generation LRMC. The timing and uncertainty in the reduction in the LRMC is assessed in Appendix A, section A.14. The possible net effect on New Zealand average prices over time is illustrated in Figure 8[56].

5.10.51 If prices were to rise by $3/MWh without any countervailing drop in wholesale prices there could be an allocative deadweight loss[57], associated with the price increase, estimated as $0.3m/yr[58] or $2.5m net present value. However, analysis shows that there would likely be a countervailing drop in wholesale prices over time.

5.10.52 If the transition is similar to that outlined in Figure 8 the deadweight loss would be reduced to $0m. Under a postage stamp transition option, where grid connected SI generators continue to pay a portion and a price increase to customers is avoided, this deadweight loss would be turned into an allocative gain. Estimates of the allocative gain in these situations are derived in section A.14.33 of the Appendix.

[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.

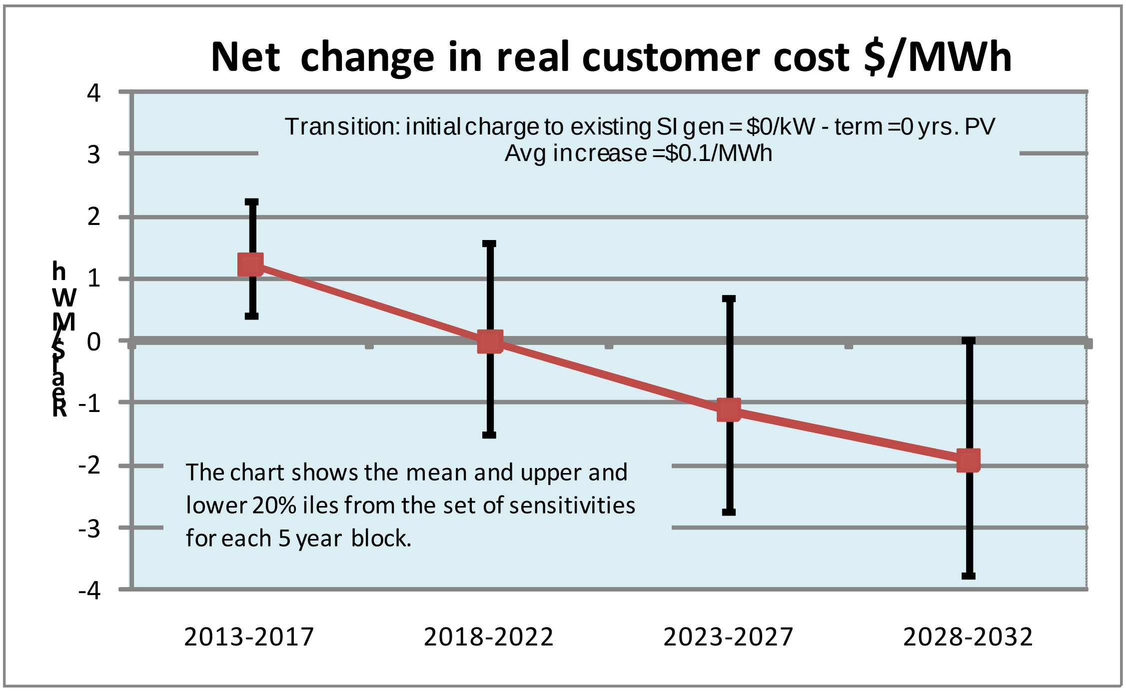
[55] If HVDC charges are allocated to all generators on a MWh basis then the effect of this is likely to flow directly through into higher wholesale prices. Similarly a 50:50 split between generators and customers would result in similar total $3/MWh increase, half coming from higher wholesale prices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

[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 recognised that the exact timing and distribution between islands will vary according to supply and demand and competitive market dynamics.

[57] 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.

[58] $3/MWh represents a 2% increase in the national average delivered electricity price of $153/MWh (MED 2010) 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 8 Possible impact of a move to postage stamping HVDC charges



5.10.53 Deadweight losses may also be offset if there are efficiency gains from higher RCPD charges deferring transmission reliability investments[59].

5.10.54 The table below summarises the unintended efficiency impacts for the HVDC options relative to the status quo.

Table 23 Application of efficiency consideration 3: unintended efficiency impacts

	Assessment relative to status quo
HVDC capacity rights	**Generation investment, peaker investment and allocative efficiency** – An analysis of the unintended efficiency impacts for capacity rights would be complex and TPAG has not undertaken this analysis as it is not in the scope of TPAG's role. 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 although it considered analysis by the Authority which identified short term productive inefficiencies due to the ability to constrain capacity on the HVDC link.
MWh allocation	**Generation investment** – Would reduce the possible generation investment inefficiency from the disincentive to invest in SI generation (+$7m).

59 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.

	Assessment relative to status quo
	Peaker investment – Would avoid penalising peak injections so avoid discouraging investment in peak generation (+0 to $31m, expected $8±8m). **Dispatch efficiency** – Would avoid penalising peak injections so reduces incentives to withhold offers of short-term generating capacity in the SI (+$0 to $5m) expected ($0m). However this negligible 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[60] 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** – **a small positive** change from the status quo..
Incentive-free allocation to SI generators	**Generation investment** – Would eliminate the possible generation investment inefficiency in the status quo by recovering costs from grid-connected SI generators using an 'incentive free' allocation, although it might introduce other incentives on existing SI generators to avoid costs depending on the design of the allocation. (+10m to $48m) expected $24±9m. **Peaker investment** – Would eliminate the possible peak investment inefficiency of the status quo. (+0 to $31m, expected $8m). **Dispatch efficiency** – Would eliminate the possible dispatch inefficiencies of the status quo. (+$0 to $5m, expected $0m). **Allocative efficiency** – Would reduce delivered prices with allocative gain (+$2.0 to $5.6m, expected $3±1m).
Postage stamp	**Generation investment** – Would eliminate the possible generation investment inefficiency by recovering costs from offtake. (+$10m to $48m, expected $24±9m). **Peaker investment** – Would eliminate the possible peak investment inefficiency of the status quo. (+0 to $31m, expected $8±8m). **Dispatch efficiency** – Would eliminate the possible dispatch inefficiencies of the status quo. (+$0 to $5m, expected $0m). **Allocative efficiency**– Can lead to slightly higher or lower delivered prices (-$0.3m to $1.4m, expected $0.2±0.5m).
Postage stamp transition	**Generation investment** – Would eliminate the possible generation investment inefficiency by recovering costs load (+$10m to $48m, expected $24±9m). **Peaker investment** – Would eliminate the possible peak investment inefficiency of the status quo (+0 to $31m, expected $8±8m). **Dispatch efficiency** – would eliminate the possible dispatch inefficiencies of the status quo (+$0 to $15m, expected $0m). **Allocative efficiency** – Should result in lower delivered prices (+$0.5 to $2.7m , expected $1.2±0.7m) – for the $30/kW and 10 year option.

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

Efficiency consideration 4: Competitive neutrality

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

a) between NI and SI generation;

b) between large incumbent and other SI generators; and

c) between different technologies.

5.10.56 The benefits of these three competitive neutrality issues have also been assessed in Appendix A. The gains from increased competition between new entrants and the dominant SI generator are assessed as $10 ± 5m NPV (see A.14.31).

5.10.57 There is also an emerging competition issue if the inter-island FTR proposal is accepted and rentals or auction proceeds are allocated to auction participants. The capacity rights option could introduce further competitive neutrality issues with the introduction of a new market.

5.10.58 Table 24 below assesses the competitive neutrality of the HVDC options relative to the status quo.

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

	Assessment relative to status quo
HVDC capacity rights	Facilitates market-based commercial grid investment. Introduces potential market power issues from rights to restrict HVDC capacity.
MWh allocation	Would reduce the competitive disadvantage to new SI peaker and mid capacity factor generation (wind and hydro).
Incentive-free allocation to SI generators	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI ($10m ±5m NPV).
Postage stamp	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI ($10m ±5m NPV). Reduces a competitive issue arising from the FTR proposal.
Postage stamp transition	Would avoid disadvantaging new SI generation relative to NI, and would avoid the risk of disadvantaging small and new entrant generators relative to the large incumbent generator in the SI ($10m ±5m NPV). Reduces a competitive issue arising from the FTR proposal.

Efficiency consideration 5: Implementation and operating costs

5.10.59 The implementation and operating costs, relative to the status quo are considered in the Table 25.

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

	Assessment relative to status quo
HVDC capacity rights	Whilst capacity rights would involve major market redesign which is outside the scope of TPAG's role, TPAG considered the possible implementation and operating costs. Capacity rights would involve significant changes to the market clearing software and settlements systems and potentially require the development of associated auctions and secondary trading markets. These options represent relatively significant changes to the current market arrangements which are likely to involve high setup and operating costs for a central body and market participants. The options are not sufficiently well developed to estimate the costs with any precision, however significant modifications to the market clearing software are likely to cost tens of millions of dollars and the development of secondary markets could cost of the order of $20 to $40m NPV if the proposed FTR market is taken as a guide[61]. Would require several years to design and implement.
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	An option to implement this given in Appendix C. This may lead to immediate disputes unless used as a transition arrangement.
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

5.10.60 As set out in section 4, good regulatory practice is made up of a number of components. This is true as a general statement and in the context of the TPM. The discussion in this section particularly considers possible wealth transfers and step changes in prices. It goes on to briefly consider whether there are differences between HVDC and AC assets that are pertinent to transmission pricing as this is relevant when considering the need for consistency over all assets. Table 26 at the conclusion of the section addresses all identified elements of good regulatory practice.

Wealth transfers and step changes in prices

5.10.61 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

[61] One submitter claimed that this cost was greater than the proposed FTR market. In fact the estimate is the same as the NPV of the implementation and operating costs of the FTR as given in page 88 of Managing locational price risk: Proposed amendments to Code, 28 April 2011.

response to the issue concerned. Where change involving a wealth transfer is justified it should be well signalled in advance and a transition should be provided so participants have time to adjust.

5.10.62 In other words, wealth transfers should be avoided unless they are justified by efficiency benefits.

5.10.63 TPAG considers that its approach is consistent with the Authority's interpretation of its statutory objective.

5.10.64 TPAG expects there would be small wealth transfers between generators from a change to a MWh allocation, but there would be more substantial short term wealth transfers from consumers to SI generators under a change to postage stamping. The likelihood of wealth transfers is not as clear for the capacity rights options and has not been investigated by the TPAG.

5.10.65 Paragraphs 5.10.49 and 5.10.50 described the short run increase in delivered energy prices from postage stamping HVDC charges.

5.10.66 Were there to be a change to postage stamping HVDC charges, the extent and size of the overall value changes in the sector are difficult to estimate with any precision because of the offsetting impacts of efficiency gains. The trends in the value changes are however likely to be as follows:

- SI generators: lower transmission costs offset by lower medium term wholesale prices may mean a value change to them that is net positive or negative in medium term;
- NI generators: lower medium term wholesale prices are likely to mean a value change to them that is net negative;
- SI customers: higher transmission costs offset by lower medium term SI wholesale prices (reflecting lower long run marginal cost of SI generation) could mean a value change to them that is most likely net positive in medium term;
- NI customers: higher transmission costs offset by lower medium term NI wholesale prices (also reflecting, although not so directly, the lower long run marginal cost of SI generation) is likely to mean a value change to them of net zero or negative.

5.10.67 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 New Zealand customers offset by future and uncertain wholesale price reductions compared to what otherwise might be expected.

5.10.68 As noted above (5.10.61) consistency and stability in pricing is important and changes which involve wealth transfers should be avoided unless there are significant efficiency benefits. The magnitude of the value shifts and potential price changes, which would result from postage stamping HVDC charges, need to be seen in the context of other changes in the market. For example increases in transmission charges arising from the major AC grid investments are likely to be of the order of $4/MWh[62].

5.10.69 There are a range of views within the TPAG as to whether the benefit of removing the generation investment and dispatch inefficiency is significant enough to justify a move to full postage stamping with its short run value impacts. The TPAG has developed a transitional option which eliminates the residual inefficiencies and minimises the value impacts.

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

5.10.70 A transitional approach to postage stamping HVDC charges which retains the historical allocation of HVDC costs to grid-connected SI generators in the short term but moves to full postage stamping over a period of time would avoid an immediate transfer of value to SI generators. The proposition would be that by the time full postage stamping was introduced, the wholesale price effects would be achieved. Some of the longer term transition options provide an expected net gain to customers to compensate for the greater uncertainty of wholesale price reductions relative to the certainty of transmission price increases.

5.10.71 The transitional approach also enables major users who face external markets enough time to adjust to changes from the Transmission Pricing Methodology that applied at the time their investments were made.

5.10.72 The transitional options use an incentive-free allocation to existing SI generators in order to achieve the full efficiency gains during the transition. The aim of the transition is to reduce uncertainty and disruption for market participants arising from a change in the TPM.

Consistency over the whole grid.

5.10.73 The TPAG has considered whether there are material differences between the HVDC and AC assets relevant to the efficiency considerations. Some of the TPAG members consider that the HVDC is dispatchable and that this makes the HVDC different from other assets but this view was not held by all members. Although the HVDC is DC rather than AC it is not significantly different to the interconnection assets between the 17 other regions in the New Zealand grid. Flows on both the DC and other AC assets are effectively controlled by Scheduling Pricing and Dispatch (SPD) software scheduling generation offers to meet demand while accounting for the constraints and losses on all transmission links. SPD does not distinguish between DC and AC assets If the proposition that AC and DC are treated in the same manner is accepted it implies that the pricing approach for DC assets should be generally consistent with the approach for AC interconnection assets.

5.10.74 This does not mean the costs of the DC assets cannot be allocated in a different manner from the AC assets if there is an efficiency justification to do so. (For example if beneficiaries and their share of costs could be readily identified for HVDC assets but not for AC assets.) Similarly, it does not mean the costs of AC assets cannot be allocated in a different manner to other AC assets if there is an efficiency justification to do so.

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

	Assessment relative to status quo
HVDC capacity rights	Whilst capacity rights would involve major market redesign which is outside the scope of TPAG's role, TPAG considered good regulatory practice issues with respect to 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 35). 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. However once implemented capacity rights would provide consistency going forward. **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. A capacity rights approach discovers who values the HVDC assets and the value they would be willing to pay so is consistent with a market-based approach.

	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 approach as other significant beneficiaries are not charged and the approach is not being applied to other interconnection links for which beneficiaries can be more objectively determined. **Consistency over time** – Would be consistent over time provided was not subject to ongoing review. **Consistency over the whole grid** – Would retain the inconsistency contained in the status quo. **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 sub group of participants. **Consistency over time** – Involves a change from the status quo creating an inconsistency over time. **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 step increase delivered prices (as for the status quo), but would involve a wealth transfer from SI generators to customers if lower LRMCs flow through to NI and SI wholesale prices. **Market fit** – Retains the distinction between DC and AC assets and introduces a new distinction between existing and new SI generation.

	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.
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. However once implemented would set out a clear transition path going forward and once fully transitioned 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** – Where the transition smoothes out wealth transfers and step changes in prices could be similar to the status quo. The transition path could minimise the risk and extent of potential net price rises to end-use customers to less than 1%. It is possible to design a transition that has no step increases in prices. **Market fit –** Similar to the status quo but slightly better to the extent it treats AC and DC assets consistently.

5.11 Cost Benefit Assessment summary

5.11.1 This section summarises the CBA with reference to each of the options assessed, and reflects the distinct views of the analysis held by the members of TPAG.

Summary of options and overall net benefits

5.11.2 TPAG has explored the alternative HVDC options that were considered in Stage 2. The outcomes are summarised in Table 27. TPAG developed an additional option which involves a transition from the current arrangements to postage stamping the HVDC costs, which is also summarised in Table 27.

Table 27 HVDC options

Option	Description	Overall net benefits
HVDC Capacity rights	Generators (or other parties) would purchase capacity rights to use the HVDC link.	More costly to implement than other options. Capacity rights would involve a major market redesign. Analysis of benefits would be complex and involve analysing issues outside TPAG's role.
MWh allocation	HVDC charge would be allocated to SI generators in proportion to MWh rather than HAMI.	May be net benefits between $3m-$23m.
'Incentive-free' allocation to SI generators	HVDC charge would be allocated to existing SI generators in a manner that removes the inefficiencies identified above.	May be net benefits between $29m-$55m, although it may introduce other adverse incentives. Strong reservations about arbitrary exercise of regulatory powers that would compromise good regulatory practice.
Postage Stamp	HVDC costs would be spread broadly across off-take customers as per interconnection charge.	May be net benefits between $28m-$54m, but strong reservations about price impacts and wealth transfers.
Postage stamp transition	As for postage stamp, but incorporating a transitional 'incentive-free' allocation to existing SI generators	May be net benefits between $28m-$54m without large price impacts and wealth transfers

Emergence of distinct views

5.11.3 Two distinct views have emerged within TPAG about this analysis and whether it provides sufficient evidence to justify a change from the status quo. One view favours making a change to the HVDC cost allocation, while the other view supports retaining the status quo. The two views are summarised in Table 28.

Table 28 Two TPAG views on HVDC charges

View	Make a change to HVDC charge	Make no change at this stage
Materiality of the problem	• There is a clear and material efficiency loss associated with the current HVDC charge that warrants a change from the status quo. • The potential efficiency gain is of a similar order of magnitude to other Electricity Authority priority initiatives.	• The benefits are uncertain because the analysis undertaken cannot take account of some factors that could have a large effect on investment outcomes. • Even if the analysis is correct, the efficiency loss is not material when compared with the billions of dollars of underlying investment in generation and transmission.
Recommended solution	• Transition the HVDC charge from SI generators to off-take customers by progressively incorporating the HVDC costs in the postage-stamped interconnection charges. • Undertake the transition with an initial charge to SI generators of $30/kW/yr and transition over a period of 10 years.	• Retain the status quo with HVDC costs allocated to SI generators. • Investigate the Capacity Rights option further.
Impact on consumers	• There is a low risk that consumers will see a net increase in costs and a likelihood that they will see a net decrease in costs after 10 years.	• There is a high risk that consumers will see a net increase in costs over the short and the long term if the proposed change to HVDC charges is made.

5.11.4 In relation to the impact on consumers, there are two views strongly held views both within TPAG and amongst submitters. It is clear that transitioning the HVDC charge from SI generators to off-take consumers via the postage stamped interconnection charge will see a gradual increase in transmission charges to consumers. The view favouring the change considers that there will be countervailing reductions in electricity prices, below what would otherwise occur, arising from the lower costs of investment in SI generation. This view was supported a number of submitters including Meridian, TrustPower, Powershop, MRP, Transpower. The view held by others on TPAG is that those potential price reductions are uncertain, but the increases in transmission charges are certain. This view was supported by submitters including MEUG, Genesis, large users and DEUN.

5.11.5 Although the wealth transfers arising from these price impacts are not considered directly as part of the cost benefit analysis, the allocative efficiency gains are accounted for, but these are relatively small compared with other investment and productive efficiency gains. In addition, the paper considers the possible impact on prices from investment efficiency impacts and competition benefits.

5.11.6 The remainder of this section considers in more detail the application of CAP 2, and in respect of those members who support a change to the TPM, the application of CAP 3 to the relevant options.

5.11.7 The section concludes by elaborating on possible postage stamp transition options, which would be recommended as part of a change to the status quo by some members.

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

5.11.8 TPAG has considered whether there is a possible efficiency gain for the long term benefit of consumers from changing the allocation or structure of the HVDC charges.

5.11.9 As noted above, some TPAG members consider that there is a clearly identified efficiency gain that would justify a change from the status quo arrangements. In the view of the other members, there is no clear efficiency gain and a change is not justified.

View 1 - Identification of possible efficiency gains for the long term benefit of consumers – majority view

5.11.10 TPAG's analysis as set out in section5.2 and Appendix A identified an opportunity for an efficiency gain through restructuring the HVDC charge. The proposition is that the status quo arrangements whereby grid-connected SI generators pay for the HVDC leads to inefficiencies in generation investment, peaker investment, and dispatch resulting in higher end prices for consumers. Once implementation and operating costs of alternative options are taken into account the possible efficiency gains from the alternative options with the greatest efficiency gains lie in the range $10m to $42m NPV. (These figures would be approximately $7m greater, if the generators do not receive the HVDC rentals). These efficiency gains should lead to reduced prices to end consumers compared to the status quo counterfactual.

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

- much of the demand for new generation over the next 5-10 years is met from relatively cheap NI geothermal irrespective of the HVDC cost allocation;
- there is a larger contribution from NI wind compared to SI wind; and
- thermal generation is modelled as being more likely to be built in the NI should additional gas supply become available.

5.11.12 The sensitivity analysis performed also tests the inherent uncertainty in the costs of developing renewable wind, geothermal and hydro projects.

5.11.13 The generation investment inefficiencies above might be justified if they are offset by transmission investment efficiencies either through more efficient investment in AC assets or future DC assets. However this does not appear to be the case for the reasons set out in 5.11.14 (AC assets) and 5.11.15 (DC assets).

5.11.14 The Stage 2 analysis of the benefits of locational signalling concluded that there were unlikely to be benefits in deferring economic transmission investments. Options to provide comprehensive locational signals for AC assets were therefore not pursued.

5.11.15 Charging SI generators for the HVDC is not likely to yield investment efficiencies through improved decision-making for new HVDC investments because:

- there is no robust, cost-effective mechanism at this time to clearly and objectively determine the beneficiaries of the HVDC and their share of the benefits;
- even if there are new regulated HVDC investments, SI generators that are allocated the full cost of the HVDC costs will not necessarily be correctly incentivised to lobby and provide improved information for the long term interests of all consumers; and
- there may be alternative incentive-based regulation or other mechanisms for investment in HVDC in the future.

5.11.16 On this basis, some TPAG members reached the conclusion that there is a clear and material efficiency gain that justifies a change from the status quo HVDC cost allocation.

View 2

5.11.17 The efficiency gains rely on some cheaper SI generation investment being brought forward ahead of more expensive NI generation as a result of the removal of the HVDC charge. This may not happen.

5.11.18 Project investment decisions are complex and involve numerous inputs. Investment decisions can be swayed by factors such as environmental consenting issues, company strategies and familiarity with particular technologies. Some of these factors are generic to all investors, some are company specific, and some can be locational in nature.

5.11.19 These factors can cause investments to be made (or not made). The HVDC charge is only one factor among many in the decision-making of generator investors. The potential efficiency gains are not sufficient to justify a change from the status quo.

5.11.20 There may also be some scenarios in which there are no, or even fewer, cheaper SI generation options, delayed as a consequence of the HVDC charge.

5.11.21 In the alternative view, the analysis does not adequately account for these factors and scenarios. On this basis, the relevant TPAG members reached the conclusion that there is no clear and material efficiency gain that justifies a change from the status quo HVDC cost allocation.

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

5.11.22 Those members who favour a change from the status quo have identified a preferred option. The following paragraphs set out, in respect of those members who favour a change, the analysis of options for addressing inefficiencies identified.

5.11.23 The options have been described in section 5.3 and were:

- HVDC capacity rights
- MWh allocation
- 'Incentive-free' allocation to SI generators
- Postage stamp
- Postage stamp transition

5.11.24 Table 29 below summarises the assessment of the options against the efficiency considerations 1-6.

5.11.25 The dollar amounts are investment efficiency calculations based on the analysis set out in Appendix A. Positive values indicate an overall efficiency gain in total NPV terms relative to the status quo. Where it is not possible to quantify the benefits, a tick represents net benefits relative to the status quo and a cross represents a worsening relative to the status quo. Question marks indicate uncertainty around possible outcomes.

Table 29 Costs and benefits of the HVDC Options relative to the status quo (HAMI)

Efficiency consideration	MWh allocation	Postage stamp		'incentive free'	Capacity rights options
		Full	Transition		
3 Unintended efficiency impacts 1. Generation investment[63] 2. Peaker investment[64] 3. Dispatch efficiency 4. Allocative efficiency	 +$7 ± 6m +$8 ± 8m -$1[65] -	 +$24± 9m +$8 ± 8m +$0m +$0.2±0.5m	 +$24± 9m +$8 ± 8m +$0m +$1.2±0.7m	 +$24± 9m +$8 ± 8m +$0m +$3±1m	 -ve ? -ve ?
4 Competitive neutrality	approx same	+$10±5m	+$10±5m	+$10±5m	✓X[66]
5 Implementation & on-going costs	-$1m	-$1m	-$2m	-$2m	-$20-40m[67]?
Quantified benefit (NPV 30yr)	+$13±10m	+$41±13m	+$41±13m	+$42±13m	**?**
1 Beneficiary pays[68]	same	?	?	?	✓
2 Locational Pricing[69]	✓	✓	✓	✓	?
6 Good Regulatory Practice 1. Consistency btw regulators 2. Durability[70] 3. Consistency over time 4. Consistency over grid 5. Wealth transfers 6. Price step changes 7. Market fit	 same ? same same small[71] none same	 same ? XX ✓ small moderate ✓	 same ? ✓ X ✓ none none-low[72] ✓	 same X X X small[73] low X	 ? ? ? X? ? ? X

63 This investment inefficiency is in respect of base load and renewable 'energy' generation options (not peaking) and would be approx $7m higher if SI generators no longer receive the value of HVDC rentals.

64 The uncertainty around these inefficiencies is explored in section A.15,

65 This could be more negative if a significant amount of SI thermal generation is built and the MWh allocation results in a more significant dispatch distortion.

66 Tick for facilitating commercial grid investment, cross for potential market power issues from rights to restrict link capacity.

67 The setup and transactions cost of the merchant link will be lower than the NZIER option.

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

69 The unintended efficiency impacts of changes in the locational signals are quantified above.

70 There are durability issues for each option, including the status quo, all of which are hard to compare with those of the status quo. The Postage Stamp Transition should be more durable relative to a full postage stamp and incentive free options.

71 Small means less than 1% (approx) change in delivered prices to customers.

Postage stamp and postage stamp transition options

5.11.26 The analysis of the unintended efficiency impacts shows that there are efficiency gains to be made from alternatives to the status quo. The analysis was undertaken across a range of scenarios, tested using sensitivity analysis, and used a number of conservative assumptions for example, the level of cheaper NI geothermal resources and the level of NI wind resource.

5.11.27 The highest efficiency benefits are estimated at $41±13m for each of the full postage stamping, postage stamp transition and 'incentive free' options.

5.11.28 Both of these involve a change to the status quo practice of allocating all HVDC charges to grid-connected SI generators. Both represent a move to a more consistent approach over the grid, and may thus result in more durable arrangements with consequent benefits associated with greater regulatory certainty.

5.11.29 The full postage stamping scores poorly on good regulatory practice as it involves a significant immediate and certain transfer of value to SI generators from consumers offset by future expected wholesale price reductions compared to what otherwise might be expected. The postage stamp transition avoids or minimises these step changes in prices and wealth transfers.

MWh allocation

5.11.30 The MWh option provides some of the efficiency gains captured by the postage stamp options. It does not involve the short term wealth transfer but also does not deliver the full generation investment efficiencies. However there are other uncertainties associated with this option.

5.11.31 Analysis shows there is an efficiency gain of $13±10m NPV to be derived by retaining the allocation of the HVDC charge to SI generators, but changing the allocation mechanism to be by MWh instead of peak injection.

5.11.32 A significant portion $8±8m of these benefits come from addressing concerns that the HAMI charge dis-incentivises the offering of existing peak capacity, the development of capacity enhancements to existing hydro plant and the development of intermittent generation with low capacity factors.

5.11.33 Although the MWh allocation removes the inefficiencies associated with the HAMI allocation it may introduce other dispatch inefficiencies. This will happen if, as a result of the HVDC charge, more expensive NI generators are dispatched ahead of SI generators. Under current market conditions this risk is small, but if there was significant thermal build in the SI, the risk increases.

'Incentive-free'

5.11.34 The analysis of the unintended efficiency impacts shows that the highest efficiency gains of all the options could be made by adopting the 'incentive-free' option. However, this option raises significant good regulatory practice issues: it is highly likely to be viewed as an arbitrary , ad-hoc charge to some participants and is not consistently applied across grid assets. These perceptions of poor regulatory practice might make the option unsustainable over the long term and might have negative impacts on future investment.

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[72] It is possible to design a transition that has no step changes in prices or wealth transfers for customers as a group, but there may be small wealth transfers remaining.

[73] This represents a wealth transfer from SI generators to customers as a group.

Capacity rights

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

5.12 Recommendation

5.12.1 TPAG recommends that the Authority:

a) consider the analysis undertaken by TPAG on the possible efficiency losses associated with the current HVDC charges;

b) complete a GEM analysis to cross-check the size of the efficiency losses calculated by TPAG; and

c) determine whether it agrees or not with either of the following alternative views:

View 1: the HVDC cost allocation should be changed to a postage stamping with a 10 year transition arrangement because:

- the efficiency losses from the HVDC charging regime are material; and
- it is not possible to clearly and objectively identify the beneficiaries of the HVDC link and the extent of their benefits. Beneficiaries are likely to change over time and objective identification of specific beneficiaries may be difficult and problematic.

View 2: the status quo should prevail because:

- the estimates of the efficiency losses have wider error bounds than the analysis shows due to factors not captured by the analysis. In light of this, it is plausible that the efficiency losses may be closer to zero (that is, not significant);
- the estimates of efficiency gains from a transition to postage stamping are uncertain because they are measured against a counterfactual of lower long run marginal cost (LRMC) of generation than implied by the status quo;
- in contrast, the shifting of HVDC charges from SI generators to off-take customers is a certainty. Under the transition to postage stamping arrangement customers will experience a certain increase in cost and an uncertain benefit; and
- it is possible to identify that the SI generators are the primary beneficiaries; other participants may derive some benefits, but these are insufficient to argue that they should pay for the HVDC.

6 Deeper or shallower connection

6.1 Problem statement

6.1.1 The current connection charges cover both the cost of assets provided at the point of connection with the grid, and additional 'deep connection' assets that are shared between connected parties with the costs allocated between connected parties in proportion to the anytime maximum demands or injections. Loss and constraint rentals derived from specific connection assets are allocated back to customers who pay for those assets.

6.1.2 Connection costs are currently approximately $122m per annum, or 20% of the total AC revenue requirement. It is estimated that around $22m of the connection costs relate to connection assets that would not be included if a shallower definition was applied covering only those assets provided at the point of service.

6.1.3 The current boundary of interconnection and connection assets may not provide sufficient incentives on participants to avoid reliability-driven transmission investments when it would be efficient to do so and it may be feasible to clearly identify the beneficiaries of more assets than those currently classified as connection assets.

The relevance of the wider regulatory framework

6.1.4 TPAG has considered problems with the TPM in reference to the overall framework of which the TPM is a part. This framework is described in 2.5 and is one in which the bulk of new transmission investments are proposed by Transpower and approved by the Commerce Commission.

6.1.5 The Transpower CapexIM is developed by the Commerce Commission and sets out how capital expenditure will be assessed and approved. The Commerce Commission is currently developing the Capital Expenditure Input Methodology and expects to finalise it in late 2011.

6.1.6 In progressing analysis of deeper connection or a deeper allocation of interconnection costs to specific customers, TPAG has considered the interaction of the TPM with the Commerce Commission's assessment and approval processes. TPAG concludes that investigation of the problem and evaluation of possible alternative options can only be carried out in light of the operation of the yet-to-be determined Transpower CapexIM.

6.1.7 This is because the benefits of all deeper connection options depend to a large extent on how effective the investment approval process, including the transmission alternatives regime, is at achieving efficient investment in transmission or least cost alternatives. Where the investment approval process and the transmission alternatives regime are highly effective, investment in alternative approaches to deeper connection or a deeper allocation of interconnection costs may not be justified.

6.1.8 In particular, if the application of the transmission alternatives regime is robust then generation and demand-side options would compete effectively with reliability-driven transmission investments and the benefits from deeper connection arrangements could be low.

6.1.9 In addition, if one of the deeper connection options considered in this section was to be implemented, the Commerce Commission would need to be able to assess beneficiaries of new reliability investments when they are considered under the investment approval process.

6.1.10 TPAG considers that any further analysis of deeper connection options requires close coordination with the Commerce Commission. Accordingly, the TPAG does not make firm recommendations for changes to the TPM in this area.

6.1.11 TPAG has, however, undertaken analysis of potential efficiency gains and considered possible alternative options. It analysis is set out in the following sections.

CAP 2: Potential efficiency gains from changes to the connection-interconnection boundary

6.1.12 There may be inefficiencies associated with the current connection definition arising from insufficient incentives to:

a) promote commercially-driven investments at the fringes of the grid;

b) provide quality information to support transmission planning and the Commerce Commission's investment approval process; and

c) defer reliability-driven investments when it is economic to do so.

6.1.13 In the Stage 2 Consultation Paper, the Commission suggested there may be possible efficiency gains from providing incentives to participants to take action to defer or avoid transmission investments where there are benefits from doing so. Providing a deeper definition of connection or allocating a deeper portion of interconnection costs directly to participants is a way of providing these incentives.

6.1.14 TPAG supports an approach that allocates costs to particular grid users on those parts of the grid where it is feasible to clearly identify the beneficiaries of the grid assets, but the quantification of potential efficiency gains face similar problems to those set out in relation to the allocation of HVDC costs in section 5.6.

6.1.15 A number of major reliability investments have already been approved and committed. Any potential value from deeper connection options can only therefore arise from new uncommitted reliability-driven investments. In addition, any analysis requires subjective judgements about:

a) how robust the investment approval process is, including the transmission alternatives regime; and

b) how the incentives applying to, and the capability of, the various parties engaging in the decision-making process for a new investment may change as a result of a change in the TPM.

6.1.16 The Commission estimated a potential value of $200-$300m NPV from deferring uncommitted reliability driven assets.

6.1.17 This estimate draws on 2010 SOO estimates of DSM and peaking plant which have since been revised downwards. It also assumed that all DSM and peaking generation investment could be relocated to avoid future reliability investments, whereas a portion of this value is likely to be achieved through the existing RCPD allocation method.

6.1.18 The total NPV of uncommitted reliability investments in the period 2015 to 2040 which could be deferred by DSM and peaking plant is estimated to be around $300m[74] (at an 8% pre tax real discount rate). This is based on assumed peak demand growth of around 150MW per year.

6.1.19 The updated SOO scenarios have a peak demand growth of around 130MW/yr and around 18% of this is met by DSM and around 13% by diesel peakers (the most flexible plant in terms of where it can locate)[75].

6.1.20 It is likely that the existing RCPD-derived charges under the status quo would provide incentives for some of the DSM options and embedded peakers, but there is scope for grid connected diesel peakers (which are needed to meet energy demand) to be located in those regions which are requiring reliability-driven grid investments. Given that these peakers were going to be built anyway (i.e. wholesale electricity prices are sufficiently high to pay for them), the cost of locating them appropriately to avoid grid investments as well is likely to be relatively low.

6.1.21 If it is assumed that 50-75% of the DSM and 25-50% of the diesel peakers will be located in regions with growing net demand (possibly as a result of the RCPD allocation method) then there may be scope for savings of up to 10-20% of the total reliability investment cost as a result of the deeper connection options. This implies a maximum potential NPV value of $30-$60m NPV, substantially lower than the Commission's earlier estimate of $200-$300m NPV.

6.1.22 Some or all of this potential gain of $30m-$60m might be available through the transmission alternatives regime as operated by Transpower under the status quo. Any participant can propose a transmission alternative if they see benefit in doing so.

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

6.1.24 TPAG notes that the greatest efficiencies will be achieved where participants that are allocated costs receive the respective decision rights.

Other potential issues

6.1.25 The following issues were raised in relation to the current definition of connection by submitters to the Stage 2 Consultation Paper:

a) TrustPower raised concerns with respect to the how contestable the provision of connection assets is, as Transpower appears to require a lower configuration standard for connection assets owned by it.

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

[75] These could be either open cycle gas turbines or reciprocating diesels.

b) Todd Energy considered it unreasonable for a generator to contribute connection assets shared between offtake and generation built to a higher reliability standard than required by the generator.

6.1.26 The TPAG notes these issues but they have not been addressed in the TPAG's work.

6.2 Submitter and Biggar Report views

6.2.1 Most submitters on the Discussion Paper consider agree with TPAG that further analysis of deeper connection options requires close coordination with the Commerce Commission, although MEUG submits that coordination is 'desirable but not necessary'. In MEUG's view, both regulators should work to meet their own statutory requirements first with opportunities for coordination taken as they arise.

6.2.2 Some large users submit that TPAG has not undertaken sufficient analysis of deeper connection options, for example, MEUG suggests that the likelihood of efficiency gains should have been assessed empirically.

6.2.3 Other submitters, for example, Transpower, believe that the Authority should agree that TPAG has undertaken sufficient justification for concluding that no further analysis should be undertaken.

6.3 Options

6.3.1 Drawing on earlier work of the Commission and the Authority, and its own analysis, the TPAG has identified alternatives to the status quo. In parallel with considering deeper connection arrangements, TPAG has also considered a shallower definition as some submitters on the Stage 2 consultation paper suggested there may be benefits in moving to a shallower connection definition.

6.3.2 These are options summarised in Table 30. The primary rationale for the development of alternatives is to find a means of allocating transmission costs in a manner that:

a) better incentivises participants to provide good quality information to Transpower's planning and the Commerce Commission investment approval processes and promote commercially-driven investment where possible;

b) provides incentives to defer reliability-driven investments when it is economic to do so; and

c) delivers a better method to deal with boundary issues between connection and interconnection.

Table 30 Options for deeper or shallower connection

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

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

Shallow connection

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

Flow tracing design

6.3.5 Flow tracing would be applied to offtake only and it would be possible to exclude assets accounted for under commercial arrangements or non-interconnection parts of the TPM (e.g. connection, deep connection, customer investment agreements, HVDC, or potentially 'but-for' agreements etc).

6.3.6 Flow tracing has been prototyped and tested to an extent by the Authority[76]. This has provided some confidence that the approach is workable and has allowed variations in the key design parameters and issues such as pricing stability to be explored.

6.3.7 A key parameter in the flow tracing is the cut-off threshold. It has been proposed that this be based on an Asset Concentration Index (ACI) based on the Herfindahl-Hirschman Index, essentially measuring the number of transmission customers sharing the asset. An ACI of 10,000 denotes a dedicated asset and by varying the ACI threshold the percentage of AC assets that were allocated or postage stamped can be determined. Table 31 below indicates the expected split of ACassets in 2015 under three alternative thresholds.

Table 31 Percentage of AC costs allocated under the flow trace Option

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

6.3.8 The flow tracing calculations would require data from SPD and be assessed every trading period. This would enable the ACI cut-off and flow shares to be determined dynamically every half hour and/or averaged over a longer time frame such as a month or year. Transmission pricing is likely to be based on accumulated annual flow shares.

6.3.9 The ACI cut-off could be based on total customer shares for each asset, but it may be better to use a regional rather than company defined assessment to avoid giving distribution companies an incentive to restructure or to embed generation to influence the cut-off[77] (i.e. disincentivise gaming behaviour).

6.3.10 It may be possible to provide a transition to flow tracing by gradually reducing the ACI threshold over time. An alternative transition might be provided by only applying the approach to 'new' assets as they are built. Note that this would require an objective basis for determining what was a 'new' transmission asset compared with one that was refurbished or replaced.

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

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

'But-for' design

6.3.11 Minimal work has been completed on how the 'but-for' option would apply in New Zealand. In order for this option to operate in practice there would need to be guidelines for how Transpower and the Commerce Commission would identify beneficiary shares when investments are approved. For offtake it may be possible to use flow tracing as a mechanism to assist in this regard. An objective basis for determining which assets are 'new' (i.e. not required to service organic growth and solely attributable to a particular party's demand or generation) would be required. In addition there may be an investment cost threshold below which the approach would not be applied.

6.3.12 It may be possible for the identified beneficiaries to enter long term contracts with Transpower (this would involve issues relating to term, performance promises etc). Alternatively the Commerce Commission might agree to approve fixed asset cost shares between parties or a methodology for allocating costs as part of the TPM.

6.4 Assessment of the options against the efficiency considerations

6.4.1 The section assesses the options using the efficiency considerations described in section 4.4 relative to the status quo.

Efficiency consideration 1: Beneficiary pays

6.4.2 The TPAG supports the application of the beneficiaries approach as discussed in section 4.4 and considers that there may be material benefits to the investment decision-making process where beneficiaries can be readily identified. The beneficiary-pays approach suggests that a deeper allocation of costs to specific beneficiaries is likely to produce benefits and both flow trace and 'but-for' would aim to allocate a greater proportion of costs to beneficiaries.

6.4.3 Table 32 assesses to what extent the alternatives apply the beneficiary pays approach relative to the status quo.

Table 32 Application of efficiency consideration 1: beneficiary pays (connection options)

Option	Application of beneficiary pays approach, assessment relative to the status quo
Shallow connection	Allocates fewer assets directly to beneficiaries than the status quo.
Flow tracing	Allocates more assets - both new and existing - to users as a proxy for beneficiaries. The flow tracing approach applies a formulaic approach to assessing beneficiary shares which is likely to be less costly to operate than 'but-for', and potentially more objective. On the other hand, flow tracing assumes that benefit is proportional to flow shares, which may not be reasonable in all cases. The assumption may be more reasonable if the flow trace is only applied to loads and the threshold is not set too deep. There may be issues if costs of reliability-driven assets are allocated to direct customers and distribution loads with different requirements for security.
'But-for'	Allocates more new assets to beneficiaries than the status quo. The 'but-for' approach links the identification of beneficiaries to the investment process and as such it allows for a gradual targeted phasing in of a beneficiary pays approach as and when it is likely to have the greatest benefits in respect to efficient grid investment decision-making. However it does require a case by case assessment of beneficiaries which involves the practical issues and transactions costs involved in identifying beneficiary shares of new investments and boundary issues on each major investment. This will involve forecasts of load and other factors and the scope for lobbying and disputes will inevitably increase if the boundary is pushed deeper into the interconnected grid. It would also require an objective basis for distinguishing between 'new' assets and other capital expenditure (e.g. replacement or refurbishment)[78].

Efficiency Consideration 2: Locational signalling

6.4.4 How strongly a methodology signals the cost of locational decisions depends to some extent on the depth that asset costs are directly allocated to customers.

6.4.5 A primary objective of both the flow tracing and 'but-for' options is to provide stronger incentives for loads to seek out cheaper options for additional load control or flexible generation[79] to delay or avoid new grid investments that they would have to pay for. The locational signal in these cases is an ex-ante signal – participants are incentivised to seek cheaper alternatives as they will anticipate higher costs being allocated directly to them once the investments are committed.

6.4.6 The following Figure 9 illustrates the potential size of the additional location signal[80] that would have been provided had flow tracing been in place prior to the approved North Island Grid Upgrade Plan (NIGUP).

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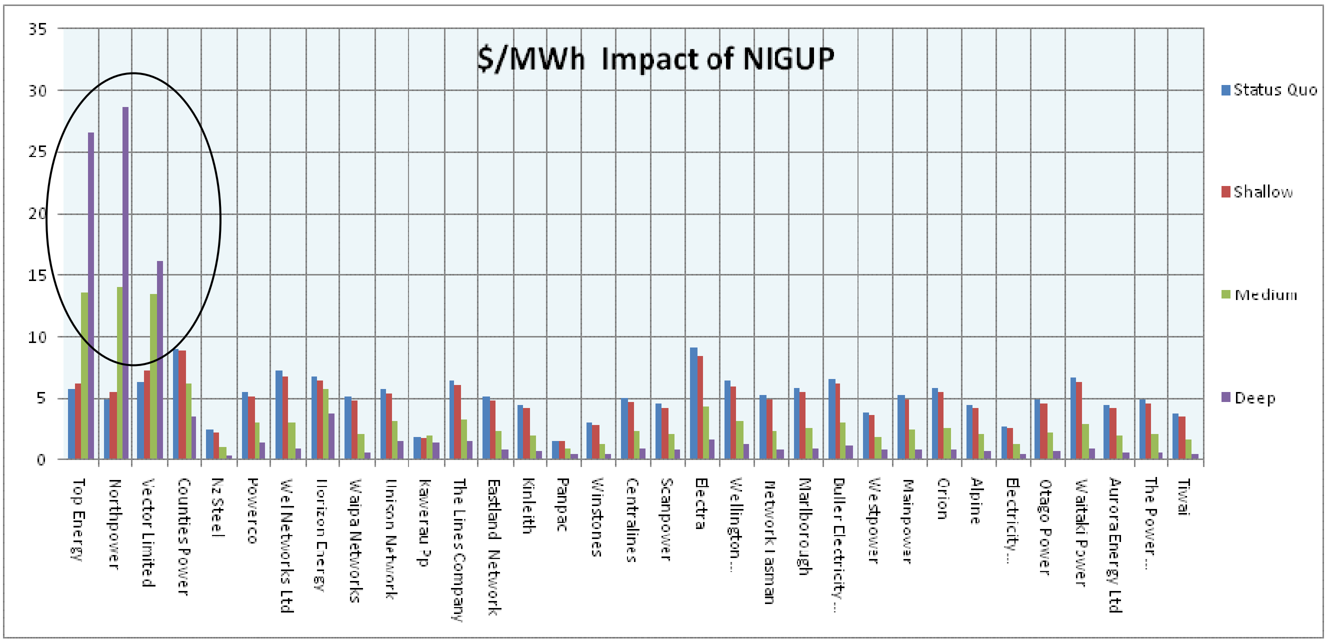
78 These practical issues are canvassed in Page 71 of Appendix 2 "Further analysis of Stage 1 options", Electricity Commission July 2010, available at: http://www.ea.govt.nz/document/9993/download/our-work/consultations/transmission/tpr-stage2options/

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

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

Figure 9 Impact of NIGUP on Customer Transmission Charges



6.4.7 Figure 9 shows that under a medium or deep flow tracing, Vector, North Power and Top Energy would have been faced with a $14 to $27/MWh increase in their transmission charges attributable to the NIGUP and NAaN (North Auckland and Northland) investments in the AC grid, compared with only $5/MWh under the status quo or a shallower flow tracing option. The prospect of paying these charges would have provided strong incentives for these companies to provide good quality information to Transpower and the Commerce Commission when the investments were being approved and to delay or avoid the grid investments by encouraging cheaper transmission alternatives if possible.

6.4.8 Both the flow tracing and 'but-for' options provide very strong 'ex-ante' incentives to promote options which can delay or avoid new grid investments before they are committed, however once a lumpy grid investment has been approved and becomes part of the fixed cost-recovery it is relatively hard to avoid[81]. This means that the incentive to actively manage load is strongest prior to a large grid investment, but then is reduced. This is sensible from an economic perspective if large investments result in a short term surplus of grid capacity.

6.4.9 On the other hand, the existing RCPD allocation method already provides an ongoing signal to manage load and to promote local embedded generation in regions where net demand is growing. In this case the incentive to control peaks is even greater following a new investment. This is reasonable where there is a series of small new grid investments required to meet growing demand but is not ideal where the investments are infrequent and large as the need for demand control is likely to be lower following a major investment. This issue might be addressed, under the status quo, by increasing the number of trading periods used to define the RCPD to 100 so as to blunt the incentive for load control while there is surplus capacity.

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

6.4.10 Both the flow tracing and 'but-for' options will reduce the level of postage stamped interconnection costs, and hence the level of the RCPD-derived charge. Under the status quo the average real RCPD derived rate is expected to increase from around $70/kW/yr to around $90/kW/yr for the period 2015-2020. This provides a relatively strong incentive to control peaks in the upper North and upper South Islands. With a medium flow tracing option this would reduce to around $45/kW/yr. The reduction would be less in the 'but-for' option as the allocation of shared costs would only be applied on new assets as they were built.

6.4.11 TPAG notes that a deeper definition of connection assets, or a deeper allocation of costs, would provide enhanced locational price signals to electricity distributors and direct connect customers, thereby providing stronger incentives to engage in the investment approval process for reliability-driven investments. Although this should help promote the consideration of transmission alternatives, TPAG also notes that the parties most likely to offer transmission alternatives would not receive this price signal directly.

6.4.12 TPAG has estimated possible benefits from the signals provided by 'but-for' and flow trace at $15m to $40m NPV, but noted that the nature of the analysis means the estimate is high-level only and even these benefits may be available through an effective transmission alternatives regime.

6.4.13 The locational signals provided by the options are summarised in Table 33.

Table 33 Application of efficiency consideration 2: locational signalling (connection options)

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

Efficiency Consideration 3: Unintended efficiency impacts

6.4.14 As with any practical cost allocation methodology there is the risk of creating perverse incentives for customers to reconfigure their networks, or to enter into arrangements with generators or loads simply to alter their allocation of transmission costs.

6.4.15 There are some anecdotal examples of this occurring under the status quo (to adjust the boundary between deep connection and interconnection assets), but this does not appear to be a significant issue, and is unlikely to be an issue under the shallow connection option.

6.4.16 There is scope for some perverse incentives arising from the flow tracing and 'but-for' options. Possible unintended efficiency impacts are summarised in theTable 34.

Table 34 Application of efficiency consideration 3: unintended efficiency impacts (connection options)

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

Efficiency Consideration 4: Competitive Neutrality

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

Efficiency Consideration 5: Implementation and operating costs

6.4.18 Implementation and operating costs have not been closely examined, but estimates are included in the Table 35.

Table 35 Application of efficiency consideration 5: implementation and operating costs (connection options)

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

Efficiency consideration 6: Good regulatory practice

6.4.19 As set out in section 4, good regulatory practice is made up of a number of components. The discussion in this section particularly considers possible wealth transfers and step changes in prices, consistency over the grid, and durability aspects of good regulatory practice. Table 36 at the conclusion of the section addresses all the elements of good regulatory practice identified in section 4.

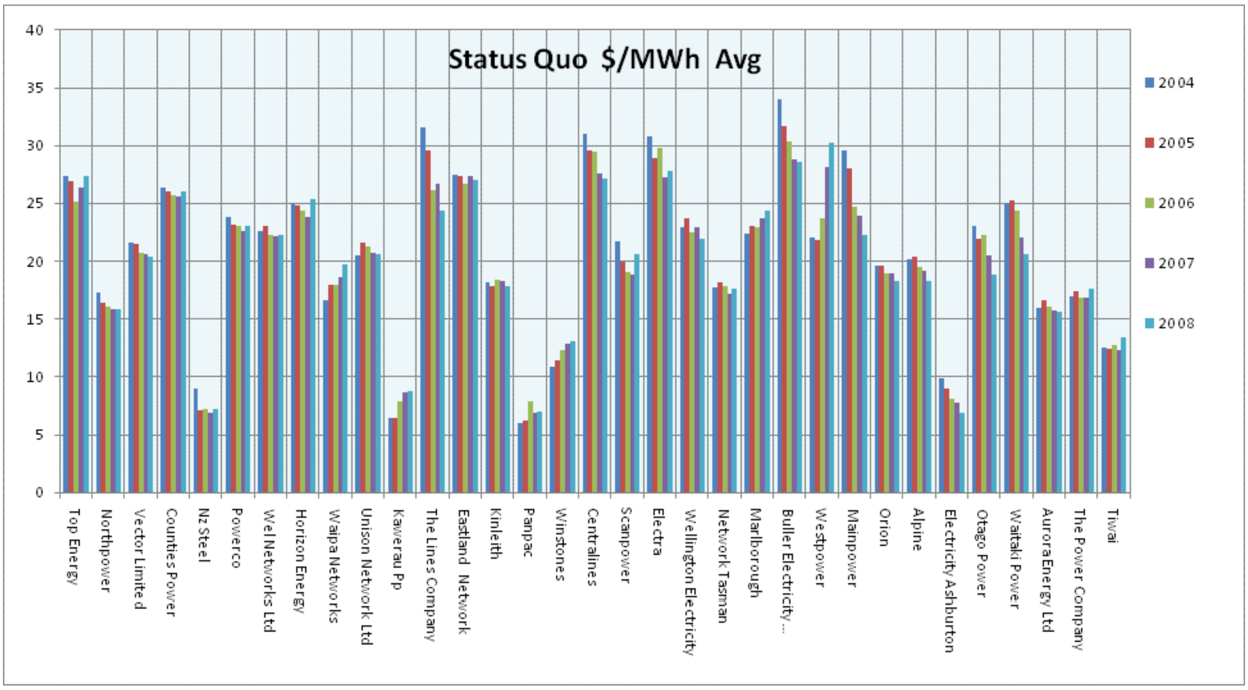
Wealth transfers and price step changes

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

6.4.21 Figure 10 shows the estimated average transmission charges in 2015 by customer under the status quo, based on scaled up demands from 2004 to 2008.

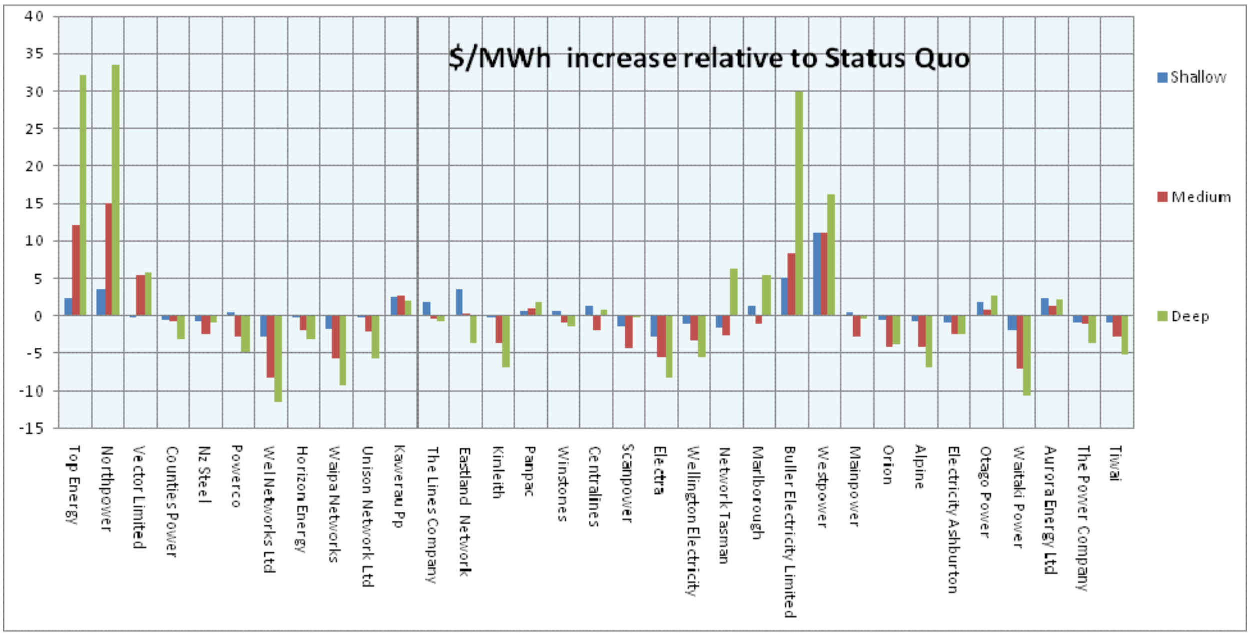
6.4.22 This is provided as a basis for comparing with the impact of implementing flow tracing. Note that under the status quo there is already a reasonable variation in average transmission charges between customers. This partly reflects different connection costs, but relates mainly to different effective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

Figure 10 Estimated average transmission charges under the status quo in 2015



6.4.23 Figure 11 shows the impact on average transmission charges from a move to flow tracing. As can be seen the price and value impacts are potentially significant with a medium and deep flow tracing methodology. Some customers would see an increase of over $30/MWh with a deep flow trace, for example. The impact is less with a medium flow tracing option, but still involves price changes in the range of +$15/MWh to minus $10/MWh. Note that the impact is variable with customers in the upper NI and the West Coast of the SI being most adversely affected. There are also some significant winners. These are substantial wealth transfers and would require significant efficiency gains to justify. Note that a component of the value impact relates to the cost of the large NI grid investments which have been recently approved. These are committed and so the potential efficiency gains from improved investment decision-making in respect of these investments are no longer available.

Figure 11 Estimated price impact of flow tracing in 2015.



6.4.24 Using a shallow flow tracing option would avoid the price impact, but this is unlikely to provide significantly better incentives for improved grid investment decision-making.

6.4.25 It may be possible to provide for a transition (for example by increasing the depth of the flow tracing over time, or by applying it to 'new' assets as they are approved), but even in this case there would be significant value impacts once the transition period has ended as there is unlikely to be significant offsetting value gains.

6.4.26 The value impacts from the 'but-for' approach are likely to be eventually similar to flow tracing, depending on the rules for determining which new assets this applies to and the rules for identifying beneficiaries cost shares. The overall price impacts should be lower with 'but-for', since it applies to only new assets. However there will still be very significant price impacts for the individual customers involved in each new investment. Both options may also create local price impacts when individual assets need to be refurbished or replaced.

Consistency over the grid

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

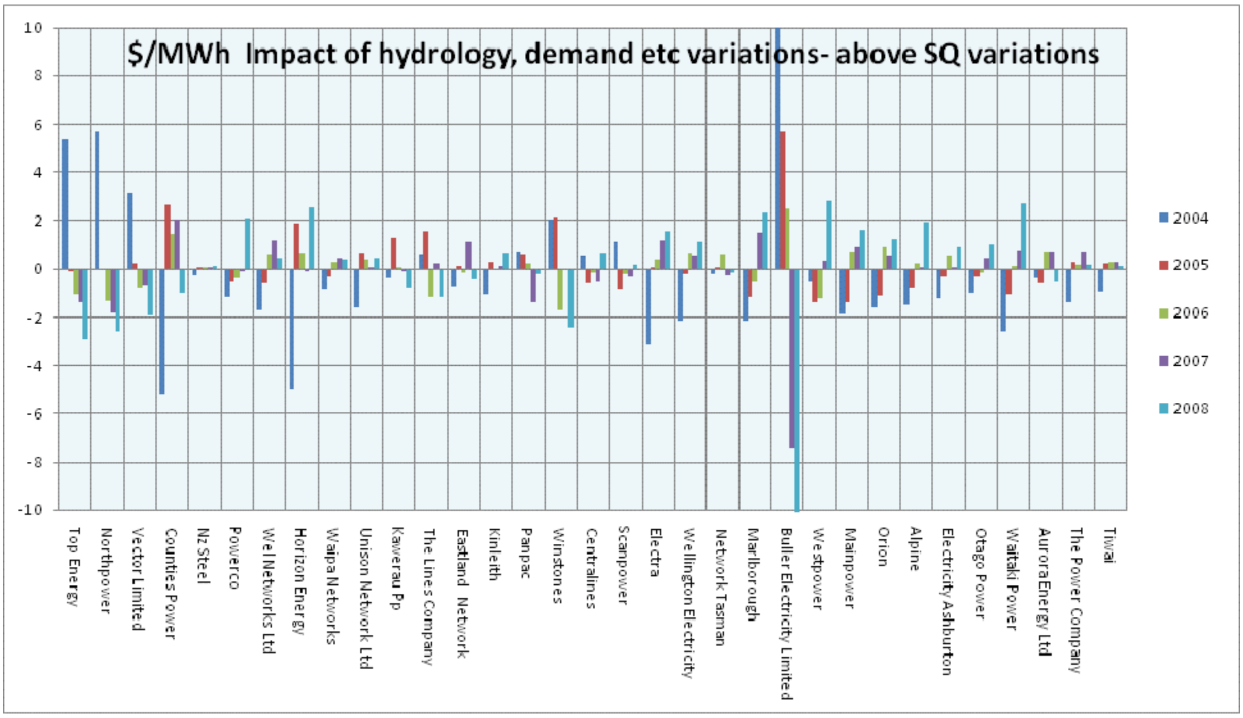
6.4.28 The 'but-for' option would be consistent in the sense that it was applied to all qualifying new grid investments, but it might result in some customers being treated differently simply because network assets in their region happened to be up for replacement or expansion. This may be efficient, but could be seen as arbitrary, and this could affect the acceptability and durability of the option and could result in costly disputes[82]. There may also be some scope for disputes over the definition and application of the cut-off in the flow tracing option.

Durability

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

6.4.30 Figure 12 illustrates the price fluctuations that might arise in 2015 with the medium flow tracing methodology over a number of years with different hydrology and demand. As can be seen the price fluctuations are relatively high for a few customers but are within the range ±$2/MWh for most customers. This would probably be acceptable as it is comparable with the fluctuations under the status quo.

Figure 12 Pricing volatility under the medium flow tracing option in 2015 with historical flow patterns



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

[82] The definition of 'new' versus 'old or replaced or refurbished' assets could be an issue in this regard.

6.4.32 Although flow tracing may be relatively complex to setup, once developed it is formulaic and should be relatively straight forward to operate and apply over time. There are a few parameters that may be subject to dispute (such as the definition and application of the cut-off).

6.4.33 The ‘but-for’ option is likely to be complex and may involve a number of specific issues concerning its application that may be disputed. These include:

a) interpretation and rules over which new assets it applies to;

b) interpretation of guidelines over how to assess beneficiary shares at the time of investment approval given that this will involve the definition of a counterfactual or baseline and a number of forecasts and assumptions;

c) issues that arise if circumstances change significantly (e.g. change in grid connections, new loads, new local generators, etc); and

d) issues relating to what happens when a ‘new’ asset needs to be replaced or refurbished.

6.4.34 Table 36 summarises the assessment of the options against efficiency consideration 6: good regulatory practice.

Table 36 Application of efficiency consideration 6: good regulatory practice (connection options)

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

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

6.5 Cost Benefit Assessment summary

6.5.1 This section summarises the CBA with reference to each of the options assessed.

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

6.5.2 TPAG has considered the possible efficiency gains from a change to the current boundary between connection and interconnection assets.

6.5.3 TPAG's analysis set out in paragraph 6.1.12 to paragraph 6.1.24 identified an opportunity for efficiency gains from incentivising customers to defer reliability investments through allocating the costs to specific participants through either a 'but-for' or flow trace approach. The estimated benefits are of the order $15m to $40m NPV, but the estimate remains high-level and depends heavily on the effectiveness or otherwise of the transmission alternative regime, the grid investment process and distribution pricing regulation. The analysis notes that an effective transmission alternatives regime may achieve most or all of the benefits.

6.5.4 TPAG has not reached a firm conclusion on whether these potential benefits justify a change from the status quo because further analysis of the efficiency gains and assessment of alternative options requires close coordination with the Commerce Commission.

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

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

Summary discussion

6.5.6 The 'but-for' approach is potentially attractive in that it extends the beneficiary pays approach in a targeted manner to new reliability-driven grid investments where the benefits in terms of locational signalling are likely to be greatest. However it may be costly to apply (depending on scope), and could give rise to a number of potentially contentious ongoing issues concerning its application.

6.5.7 The estimated efficiency benefits from the 'but-for' option may not be certain enough to justify the significant wealth transfers and price impacts that would result. Evaluation of the likely effectiveness of the transmission alternatives regime, in cooperation with the Commerce Commission, would be necessary before conclusions are possible. Further, the 'but-for' approach relies on the identification of beneficiaries at an early stage in the approval process for reliability-driven transmission investments. This also requires cooperation with the Commerce Commission since the Commerce Commission would need to be able to assess beneficiaries of new reliability investments when they are considered under the investment approval process.

6.5.8 The flow tracing approach is attractive in that, once established, it may be simpler and less contentious to operate over time than the 'but-for' option. However participant benefits are not always proportional to flow shares, and the price impacts and wealth transfers would be even more widespread. These might be mitigated to an extent by providing some form of transition.

6.5.9 The estimated efficiency benefits from the flow tracing option may not be certain enough to justify the significant wealth transfers and price impacts that would result. Evaluation of the likely effectiveness of the transmission alternatives regime, in cooperation with the Commerce Commission, would be necessary before conclusions are possible.

6.5.10 More evidence of significant problems arising from the existing deep connection approach is required to justify a move to a shallow definition of connection assets. The costs and difficulties of identifying the beneficiaries of deep connection assets do not appear to be sufficient to outweigh the benefits of retaining this approach.

6.5.11 Table 37 compares the main connection pricing options relative to the status quo. Where possible quantified benefits and cost estimates are included. Positive values indicate an overall efficiency gain in total NPV terms. Where it is not possible to quantify the benefits, a tick represents an improvement relative to the status quo.

6.5.12 The flow tracing option is assumed to be of medium depth for this assessment, as a shallow approach is unlikely to deliver significant efficiency gains, and a deep approach has more significant price impacts and wealth transfers.

Table 37 Assessment of the connection options relative to the status quo (deep connection)

Efficiency consideration	Shallow connection	Flow tracing (Medium)	'But-for'
2 Locational Pricing	Negative?	\$15-\$40m	\$15-\$40m
5 Implementation & operating costs	\$0m?	-\$12-10m?	-\$15-5m?
Quantified benefit (NPV 30yr)	**Negative?**	**+\$3 to \$30m**	**+\$0 to \$35m**
1 Beneficiary pays	x	✓[83]	✓✓[84]
3 Unintended efficiency impacts Game boundary, cut-off and cost allocation	✓	*X*[85]	*X*[86]
6 Competitive neutrality	same	same	same
6 Good Regulatory Practice 1. Consistency btw regulators 2. Durability 3. Consistency over time 4. Consistency over grid 5. Wealth transfers 6. Price impacts 7. Market Fit	 same ✓ same same low low same	 *same* *X* *X*[87] ✓[88] ± \$10/MWh ± \$10/MWh[89] same	 Needs coordination XX[90] *X*[91] *X*[92] ± \$5/MWh[93] ± \$5/MWh same

83 Flow tracing applies to all assets but assumes that benefits are proportional to flows for loads which is not necessarily the case.

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

85 There would still be some incentives to influence demand or generation to alter cost shares with Flow tracing.

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

87 Flow tracing appears to be reasonably stable year on year, although there could be special cases where it is not.

88 Flow tracing can be applied relatively consistently across the grid, and may be slightly more consistent that current approach.

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

90 Scope for disputes is high, and there is a different application to old and new assets.

91 May be stability issues when assets need to be replaced or refurbished.

92 'But for' would treat old and new assets differently.

93 Only applies to customers benefiting from 'new' assets.

6.6 Recommendation

6.6.1 TPAG recommends that the Authority:

a) note TPAG's view that the evaluation of deeper connection options cannot be completed until the Transpower CapexIM is determined by the Commerce Commission under section 54S of the Commerce Act 1986; and

b) consider engaging with the Commerce Commission to explore further the extent to which benefits might accrue if there is a deeper allocation of costs to customers and the possible mechanisms for implementing such a change.

7 Static reactive compensation

7.1 Problem statement

Background

7.1.1 SRC refers to sources of reactive power[94] that provide local voltage support and increase power transfer limits into regions that are subject to voltage instability. Both the Upper North Island (UNI) and Upper South Island (USI) are regions where the transmission capacity of Transpower's grid is capped by voltage stability limits.

7.1.2 Improving the power factor[95] of loads (by lowering their reactive power consumption), and/or providing additional SRC within networks at or near the load centres are both ways of increasing voltage stability limits[96] and decreasing network losses[97].

7.1.3 Transpower has forecast the need for substantial levels of reactive power investment in the UNI and USI regions for the next 10 – 15 years[98]. A proportion of this investment is required to support the reactive power demands of transmission customers, while the balance is required to provide the reactive power needs of the grid itself. Although the investment in SRC assets is relatively small in comparison with the overall scale of current transmission investments, the benefits, in terms of extending existing transmission capacity and the consequent deferral of major transmission line upgrades, are large.

7.1.4 In some circumstances, SRC investment would be more efficient if the equipment was located within local distribution networks or in end-use customers' electrical installations, rather than within the transmission network[99].

7.1.5 Status quo arrangements rely on the power factor standard in the Connection Code[100] to determine the allocation of costs for SRC investment. This mechanism relies on the parties to the

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

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

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

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

98 Transpower, Annual Planning Report 2011.

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

100 The Connection Code is incorporated into the Code by reference at Clause 12.26. The relevant section (4.4 Minimum power factor) requires from 1 April 2010 for power drawn off the grid, that the customer must maintain a power factor of not less

bilateral transmission contract framework to make alternative arrangements (non-compliance agreements) where the requirements in the Connection Code are not able to be met for particular points of service. However, these arrangements have been controversial with offtake transmission customers and Transpower.

7.1.6 Offtake customers in the UNI and USI regions have argued that the 'unity power factor' requirement in the Connection Code, intended by the Commission as an investment cost allocator, puts them in automatic breach of the Connection Code, as it is not possible to achieve an exactly unity power factor in practice[101]. Note that the LSI and LNI regions are treated differently in respect of minimum power factor than the USI and UNI regions. In general, these regions are not constrained by voltage stability considerations and are therefore not considered as part of the issue being discussed in this section.

7.1.7 Transpower has argued that the mechanism within the Connection Code for dealing with the issues associated with power factor measurement accuracy and the inevitable breaches of the requirement that will arise is unworkable. A standoff situation has developed, whereby Transpower has, in some cases, entered into non-compliance agreements with some offtake transmission customers and for others not complying chosen, at least for the time being, not to pursue the matter.

CAP 2: Possible regulatory failure and efficiency gains?

7.1.8 The objective of any approach to charging for SRC is to incentivise efficient investment in SRC equipment by ensuring that offtake transmission customers pay a cost-reflective charge for the reactive component of power flowing into distribution networks or a directly connected customer's premises. This objective is consistent with the Authority's statutory objective.

7.1.9 The status quo arrangements are problematic for two reasons:

a) the status quo, relying solely on the absolute unity power factor requirements of the Connection Code for the UNI and USI regions is not possible to comply with; and

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

7.1.10 The TPAG concludes that the combination of these two factors indicates a regulatory failure that, if not remedied, may lead to dynamic inefficiencies in the way that investments in SRC equipment are made. In addition, it may be possible to clearly identify the beneficiaries of static reactive compensation investments.

Submitter views

7.1.11 Submissions supported a broad acceptance that a problem exists and agree with TPAG's consideration of relevant background and definition of the problem as a regulatory failure.

7.1.12 Against this consensus view was RTANZ, which considered that TPAG had not stated why it came to a different conclusion to the former Electricity Commission on the question of whether the requirements for a unity power factor were practically achievable. RTANZ did, however,

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than 1.0 (unity) at each relevant point of service during each relevant regional peak demand period in the UNI Region and the USI Region.

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

acknowledge that status quo arrangements have not found favour with distributors and Transpower and for this reason they are unlikely to work in practice.

7.1.13 Vector commented on TPAG's summary of the relevant history to the issue, but did support the view that the problem as defined represents a regulatory failure.

7.1.14 TPAG notes that submissions received were broadly supportive that TPAG had described the relevant background to this issue and correctly identified that a regulatory failure exists.

The Biggar Report

7.1.15 Section 8 of the Biggar Report discussed the approach taken in the problem definition section. It considered that there was a lack of analysis in the Discussion Paper surrounding the underlying problem with respect to the SRC issue. It also considered that the problem of enforcement of the existing regulations faced by Transpower had not been fully explored or options developed that would remedy this problem.

7.1.16 The TPAG notes that consideration of the issue of GXP power factor in the context of ensuring efficient investment in new SRC equipment has been the subject of on-going investigation by the former Electricity Commission and now the Authority for a considerable period of time. Two rounds of consultation were carried out by the Electricity Commission that explored the problem definition and the nature of the enforcement issue in considerable detail and resolved that options for establishing an incentive regime in the context of the TPM should be developed and considered against the status quo.

7.1.17 TPAG's scope was to continue development of options from the point that the Electricity Commission had reached and to consider these options under the Authority's statutory objective and, where appropriate, apply the CAPs. TPAG is comfortable that its approach is in accordance with its terms of reference and that the analysis and recommendation developed is in accordance with the Authority's statutory objective. TPAG also notes the broadly supportive submissions received in the earlier consultation rounds undertaken by the Electricity Commission for a market based incentive mechanism developed within the TPM.

7.2 The options

7.2.1 This section:

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

7.2.2 The Stage 2 Consultation Paper suggested that there may be benefits in alternative reactive power investment regimes. It proposed three possible alternatives to the status quo. These options are summarised in Table 38.

Table 38 Reactive power stage 2 options

Option	Description	Rationale for Change
Status quo	No change to current arrangements, whereby the Connection Code requires that grid off-take at points of service have unity power factor during periods of regional coincident peak demand.	
1: Amended status quo	Widen the acceptable power factor range by requiring that off-take customers maintain 'unity or leading power factor[102]' during regional peak demand periods. Otherwise, as for the status quo option, retain the Connection Code enforcement mechanism.	A power factor range is practically achievable. It should remove the concerns in respect of the status quo requirement to maintain unity power factor. Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the transmission customer, who could choose between alternatives.
2: Connection asset definition	Include new regional SRC equipment within the definition of connection assets. Widen the status quo power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.	Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the offtake transmission customer, who could choose between alternatives. If a net reactive power demand persists during periods of regional peak demand, any grid-connected SRC equipment necessary to supply this demand is charged user-specifically to the offtake transmission customer causing the demand, via the connection charge. The Connection Code power factor requirement is widened to provide a fall back *de minimis*.
3: kvar charge	A new reactive power charge is implemented that charges offtake transmission customers for the reactive power taken off the grid by them during regional peak demand periods. The charge is set at a level that reflects the investment costs of providing new regional SRC equipment. Widen the power factor range within the Connection Code to provide a fall back minimum power factor of 0.98 lagging.	Investment efficiency remains incentivised by allocating responsibility for point of service power factor correction to the offtake transmission customer, who could choose between alternatives. If a net reactive power demand occurs during periods of regional peak demand, a charge is levied for this. The Connection Code power factor requirement is widened to provide a fall back *de minimis*.

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

7.2.3 The following sections elaborate on the options identified in the Table 38[103].

Status quo option

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

a) The power factor requirements in the Connection Code are intended to form the basis of cost allocation. Users taking reactive power off the grid at a point of service at times of peak regional demand are allocated responsibility for the costs of its provision in the UNI and USI regions.

b) The Connection Code forms part of the transmission agreement between Transpower and its customers and enforcement of the provisions of the Connection Code is therefore a bilateral matter between Transpower and its customers.

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

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

a) investing in SRC equipment themselves and locating it optimally within their distribution networks[104];

b) requiring or incentivising their end-use customers to invest in power factor correction equipment or in appliance choices that provide good power factor performance; and

c) entering into a new investment agreement with Transpower, which would provide and operate large-scale SRC equipment (e.g. static capacitor banks) connected to the grid within the local region.

Amended status quo option

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

7.2.7 An amended status quo option would involve amending the minimum power factor standard in the Connection Code for the USI and UNI regions to ‘unity or leading power factor’ (rather than

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

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

'not less than unity power factor') and retaining this standard as a basis for determining the allocation of costs for any grid-based SRC investment.

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

Connection asset definition option

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

a) widening the definition of 'connection asset' to include new SRC investments to the extent to which they deliver reactive power to offtake transmission customers in a region; and

b) retaining but relaxing the power factor requirement in the Connection Code to 0.98 lagging, so as to provide a fall-back power factor provision.

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

a) calculating the average kvar taken by an offtake transmission customer in the regional peak demand period in the relevant region (either the UNI or USI region); and

b) dividing the amount determined in a) by the total capacity of all SRC assets in the relevant region.

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

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

a) provide power factor correction measures within their own networks (and/or encourage/require their end-use customers to do so within the customers' electrical installations); or

b) rely on Transpower to provide power factor correction through investment in grid-connected SRC equipment, for which they would incur a cost-reflective charge.

kvar charge option

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

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

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

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

TPAG review of options

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

Option 1 – amended status quo

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

Option 2 – connection asset definition

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

a) Defining regional SRC assets as 'connection assets' adds complexity by effectively creating two sub-classes of connection assets that differ in the ways they are charged for:

i) 'normal' connection assets, the costs of which are recovered through asset-specific $/year charges invoiced monthly to offtake transmission customers; and

ii) 'static reactive support' connection assets, the costs of which are recovered through a new charge that is based on each in-region offtake transmission customer's aggregate kvar draw at its points of service, following establishment of the annual RCPD period.

b) Linking a charge asset-specifically to identified SRC equipment (such as specific grid-connected static capacitor banks) would imply that new investments should be subject to new investment agreements, in the same way that other new investments in connection assets are made. This would involve a multi-party negotiation, potentially involving high transaction costs and hold-out by parties.

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

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

Option 3 – kvar charge

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

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

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

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

Option 4 – amended kvar charge

7.2.26 In essence, a price signal should enable offtake transmission customers to make efficient choices between:

a) investing in distribution SRC equipment themselves;

b) relying on Transpower to invest in grid SRC equipment; and

c) encouraging or requiring their end-use customers to likewise take steps to improve any poor power factor within their load.

7.2.27 The principle that offtake transmission customers should face the costs incurred for their average aggregate kvar draw from the grid at times of RCPD provides an appropriate cost allocator.

7.2.28 Existing grid SRC assets that provide regional reactive power needs are currently incorporated within the interconnection asset base and their costs are recovered through the interconnection charge. Accordingly, the revenue raised by Transpower through a new kvar charge should displace revenue that would otherwise be recovered through the interconnection charge.

7.2.29 A methodology similar to the current interconnection charge could apply to the kvar charge and work as follows:

a) Transpower determines the LRMC of nominal grid-connected SRC equipment, following guidelines to be established by the Authority. This provides an efficient kvar charge rate and can be arrived at by dividing the estimated annual capital and operating costs of a new grid SRC asset (or group of assets) by the effective capacity[105] it (they) would provide. Accordingly, the charge would not be linked to any specific existing grid SRC assets but would be reflective of Transpower's new investment and operating costs for grid SRC assets in general.

b) Transpower uses the kvar demand data from the RCPD periods from the immediately preceding September – August capacity measurement period. From this data, it assesses the average reactive power draw from the grid in kvar, for each offtake transmission customer in the UNI region and the USI region. If an offtake transmission customer's net reactive power

[105] The 'effective capacity' (as opposed to the nameplate capacity) will need to be considered further when guidelines are established. The key factor to determine is the assumed utilisation of the SRC asset in the RCPD period.

flow during the assessment period is 'negative' (i.e. reactive power is injected <u>into the grid</u>), the assessed quantity is set at zero.

c) Transpower calculates the expected revenue to be recovered from the kvar charge for the coming year by multiplying the result in a) by the sum of the offtake transmission customer results in b).

d) The interconnection charge is calculated as it is now, except that the expected kvar charge revenue determined in c) is subtracted from the interconnection revenue before the interconnection rate is calculated. This ensures that Transpower's target revenue is the same as it would have been without the kvar charge.

7.2.30 Thus, the current year's kvar charge is set based on the immediately preceding year's kvar demand, using a similar approach to that used for the interconnection charge. The benefit for an offtake transmission customer from decreasing its reactive power draw from the grid during the RCPD period is gained in the following year, since the impact of reduced reactive power draw is reflected in the following year's kvar charge.

7.2.31 A kvar charge calculated based on the methodology outlined is illustrated in Table 39.

Table 39 Amended kvar charge (indicative only)

	USI region	UNI region	Comment
LRMC of grid SRC equipment = kvar charge rate (per annum)	$4 – 5 /kvar[106]	$4 – 5 /kvar	c.f. 2011/12 interconnection rate @ $76.14/kW
RCPD total reactive power demand	90 Mvar	285 Mvar	From 2010 RCPD data
kvar charge revenue (per annum)	$0.36 – 0.45m	$1.14 – 1.42m	
<u>Reduction</u> in interconnection rate (due to revenue substitution to the kvar charge)	$0.26 – 0.32 /kW (= 0.34 – 0.42 %)		From 2011/12 TPM[107]: Interconnection rate = $76.14 /kW Total RCPD = 5,872 MW

7.2.32 Some submitters questioned what methodology Transpower would use to calculate the LRMC of grid-connected SRC equipment and expressed some views on what should be considered.

7.2.33 Transpower also expressed a view that the indicative rate might be too low when the actual utilisation of the SRC investment is taken into account. It suggested a refinement to the methodology used to determine the kvar charge rate. Its objective in proposing this refinement is to level the playing field between grid and distribution network investment in SRC equipment. The issue it sees is that the kvar charge rate proposed would be set at too low a level relative to cost recovery of equivalent investments a distributor may make on its network because SRC equipment will never be operated at full capacity in practice.

7.2.34 Transpower's suggested refinement is "to calculate the TPM kvar charge using the WACC return method originally proposed by Transpower but basing the return on the replacement cost of new

[106] Based on indicative replacement costs for 220 kV and 110 kV static capacitor banks, provided by Transpower.

[107] Interconnection rate data from http://www.transpower.co.nz/f4358,41345188/appendix-2-transmission-pricing-2011.pdf

static reactive assets, rather than on the book value of the assets actually in place." Transpower acknowledges that this would result in a higher kvar charge rate that would "over-recover a return on the static reactive assets actually being used (and hence would represent a small cross subsidy from the users of static reactive assets to the users of all other interconnection assets)."

7.2.35 Transpower also points out a problem that "the estimated current replacement costs of static reactive assets could be challenged." It states that "this could be resolved by specifying in the TPM that the estimates used are to be values determined by Transpower in its sole discretion."

7.2.36 TPAG's view is that the principle of setting the kvar charge rate at the LRMC of grid connected SRC investments that Transpower would normally consider in the course of its grid planning function is sound. However, it is clear that the details of the process Transpower would need to follow to determine the kvar charge rate will need to be established. TPAG refers this to the Authority for further consideration.

Retention of a minimum power factor?

7.2.37 While the proposed incorporation of a prescribed minimum power factor may appear to be unnecessary where an efficient, uncapped charge is provided for grid-supplied reactive power, TPAG considers there is a case to specify a minimum level as an additional backstop measure.

7.2.38 Power factors in the UNI and USI during RCPD periods are generally at very good levels currently[108] following a period of steady improvement in the USI region over the last decade, while the UNI has remained relatively flat. However, while this trend is unlikely to dramatically reverse in the short to medium term, TPAG considers it prudent for offtake transmission customers to retain a focus on a minimum level of power factor. The options are:

a) retain a minimum power factor requirement in the Connection Code for the UNI and USI regions as a backstop to any price signalling approach; and

b) provide a penalty charge for reactive power demand in excess of the level required to maintain a target minimum power factor.

7.2.39 Option a) appeared to TPAG to suffer from the enforceability issues discussed earlier in respect of the status quo option variants. Option b) could strongly signal a minimum power factor if such a charge were set at a sufficiently high rate.

7.2.40 The question of at what level the minimum power factor should be set also arises. While a minimum of 0.98 lagging was discussed in earlier consultation, there appears to be little rationale in support of such a minimum. Since the objective is to provide a backstop measure, a minimum level corresponding to the long-established benchmark of 0.95 lagging would seem to be the most appropriate. This would provide alignment across the whole grid.

7.2.41 Regarding the level at which the penalty rate should be set, it would need to be high enough to trigger investment in transmission alternatives. In a report prepared for the Electricity Networks Association and submitted in an earlier consultation round, SKM provided budgetary costs for a

[108] For 2010 the USI power factor during the RCPD period was ~0.996 (c.f. 0.972 in 2000) and the UNI was ~0.991 (c.f. 0.991 in 2000).

range of distribution static capacitor bank options. The most expensive distribution option cost around $11 / kvar[109]. Thus, a penalty charge of around $15 / kvar would appear to be suitable.

7.2.42 For these reasons, TPAG proposed in its Discussion Paper for consultation that a penalty rate of the order of $15 / kvar should apply for reactive power offtake in excess of the level corresponding to a power factor of 0.95 lagging[110]. To be clear, the two rates were proposed to apply progressively: the kvar charge would apply for demand between 1.0 and 0.95 lagging power factor and the kvar penalty charge would cut in and apply only for any additional reactive power demand between 0.95 lagging and 0.

7.2.43 Most submitters that responded to this question indicated support for retention of a minimum power factor of 0.95 lagging as a backstop measure and supported the proposed penalty rate of $15/kvar applied to the component of reactive power consumed at power factors between 0 and 0.95 lagging.

7.2.44 Submitters opposed to the proposal of applying a penalty kvar charge rate below 0.95 lagging considered that a minimum power factor level should not be necessary where an efficient price signal is in place.

7.2.45 In considering these views, the TPAG is persuaded that a penalty charge mechanism is not necessary, but remains of the view that a clear signal should be retained that it is not a desirable operational state that offtake transmission customers operate their GXPs at a net power factor below 0.95 lagging, in any region but particularly within the constrained upper-island regions. This was identified as option a) above.

7.2.46 While it has been argued that the minimum power factor requirements in the Connection Code are impractical for Transpower to enforce, nevertheless the retention of a minimum level would still provide a clear signal of expectations. Accordingly, TPAG has settled on the view that:

a) the minimum power factor set in the Connection Code should be set at 0.95 lagging for all regions; but that

b) there should be no penalty charge introduced; and

c) the situation should be closely monitored by the Authority.

Options selected for assessment

7.2.47 The TPAG has concluded that the options that will be assessed against the status quo in the following section are:

a) Option 1 – amended status quo; and

b) Option 4 – amended kvar charge

7.2.48 Submissions broadly supported TPAG's selection of options for assessment. Two other options were suggested for consideration.

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

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

7.2.49 Some submitters suggested consideration is given to an option that bases the whole of the interconnection charge on a $/kVA rate, as opposed to the current methodology which is based on $/kW. The rationale is that such a methodology would provide the price signalling benefits sought in respect of SRC investments while being simpler to implement than the other options.

7.2.50 After considering these views, the TPAG is not in favour of a $/kVA methodology for the whole of the interconnection charge because:

a) adopting a $/kVA basis for the whole of the interconnection charge would introduce a change to the interconnection charge, particularly in respect of the lower island regions, where there is no demonstrable need;

b) $/kVA and $/kvar provide different price signals – a kVA denominator provides a variable price signal[111] in respect of reactive power that is not linked to the LRMC of grid SRC equipment, whereas a kvar denominator provides a fixed price signal that relates only to the reactive power component and that can be set at the LRMC of grid SRC equipment; and consequentially

c) such a methodology would provide a significant risk of unintended consequences.

7.2.51 Powerco suggested that poor power factor is subject to a penalty charge and that the revenue obtained from this charge is given to distributors that have poor power factor to enable them to invest in power factor correction equipment that they would locate close to loads.

7.2.52 TPAG does not favour this option, because the parties that would pay penalties for maintaining a poor power factor would be the same parties benefiting from the funds that would subsidise remedial investment.

7.2.53 In summary, having considered feedback received from submissions, the TPAG is comfortable that it has selected the appropriate options for detailed assessment against the efficiency considerations.

7.3 Assessment of options against efficiency considerations

7.3.1 This section assesses the amended status quo and amended kvar charge options against the efficiency considerations relative to the status quo.

Efficiency consideration 1: beneficiary pays

7.3.2 The TPAG supports the application of the beneficiary pays approach as discussed from paragraph 4.5.2 onwards. There are benefits to the investment decision-making process where beneficiaries can be readily identified, noting that, as explained in paragraph 4.5.8 it is not necessary to identify all beneficiaries. The costs passed to beneficiaries should not outweigh the benefit they receive and the costs incurred identifying the beneficiaries should be relative to the efficiency gains expected.

7.3.3 In general, the beneficiaries of grid-connected SRC equipment can be readily identified at points of service because the static reactive support service being provided is:

[111] The price signal for reactive power inherent in a $/kVA methodology would vary by power factor, between zero (at unity power factor) and the full interconnection rate, currently ~$76/kVA, at zero power factor.

a) able to be clearly defined – it is the provision of an aggregate average quantity[112] of reactive power that flows into the point of service during the RCPD period and can be expressed as an average demand over the assessment period in kvar;

b) measurable – revenue-grade metering equipment is located at every point of service that records both real and reactive power flows in each direction in each half hour trading period (so-called four-quadrant metering);

c) provided on a bilateral basis; and

d) able to be valued – it can be directly related to the LMRC of SRC assets.

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

a) major grid upgrades of transmission capacity into voltage constrained regions (such as the UNI and USI regions), typically involving the addition of new inter-regional transmission lines; and

b) investments in regional SRC equipment, such as:

i) grid and distribution network connected static capacitor banks; and

ii) demand-side management options, such as in-premises power factor correction equipment or selection of high power-factor appliances.

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

7.3.6 Thus, if an offtake transmission customer maintained an aggregate poor power factor across its points of service within a region in regional peak demand periods, Transpower would seek to invest first in all available lower cost options before seeking to have a major transmission line investment approved. Lower cost options would normally include one or more stages of grid-connected SRC equipment within the constrained region (up to the point where all of these options were exhausted[113]).

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

Conclusion on beneficiary pays

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

[112] Reflecting that reactive power can flow in either direction at any instance in time and that the assessment of service provision in this case will be in half hour periods.

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

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

7.3.9 Option 1 would implement a beneficiary pays approach if offtake transmission customers were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which would rely on the same mechanism.

7.3.10 Option 4 would implement a beneficiary pays approach based on point of service reactive power demands in the previous year and does not rely on offtake transmission customers concluding new investment agreements with Transpower with the attendant problems of high transaction costs and holdout. It is therefore assessed as being superior to the status quo option in this respect.

Efficiency consideration 2: location price signalling

7.3.11 Location price signalling in the context of transmission pricing can incentivise efficient co-ordination of demand-side, generation and transmission investment and efficient trade-offs between the costs and benefits of reliability.

7.3.12 The spot market in New Zealand has been developed within a framework that considers only the flow of inter-nodal real power. Reactive power flows are not taken into account and thus no pricing signals are provided for it within the energy market.

7.3.13 In terms of the current TPM, existing regional SRC installations are classified as interconnection assets – accordingly, the costs are recovered on a non-locational basis.

7.3.14 The choice and location of alternative investments in regional SRC equipment (including demand-side alternatives) has a material bearing on both the costs and range of benefits provided. For example, the following hypothetical alternative investments could provide valid solutions to improve poor power factor within a region:

a) Transpower builds a 50 Mvar static capacitor bank at a major regional transmission node.

b) A distributor within the region installs 0.75 Mvar pole-mounted capacitor banks at 50 locations and gains a power factor side-benefit from replacing several overhead 33 kV sub-transmission circuits with underground cables.

c) Large industrial customers install power factor correction capacitors in their premises and all customers select high power factor appliances (e.g. high power factor compact fluorescent lighting).

7.3.15 While each of these alternatives on its own, or a mix of combinations of parts of each alternative, could provide satisfactory voltage support across a network region, each investment will involve unique costs and benefits (i.e. the costs and benefits are location dependent). Some level of investment at each of the transmission, distribution and end-consumer levels is likely to provide an optimal level of efficiency by maximising transmission and distribution capacity while minimising electrical losses. Seeking to provide a location price signal for investment in SRC equipment is therefore likely to be beneficial (particularly if such a signal is also provided to end-consumers).

Quantification of benefits

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

Loss reduction benefits

7.3.17 Estimates of distribution network loss reduction benefits have previously been made[114]. SKM estimates that improvements in power factor, in the case of their analysis to unity, could provide approximately $10m in loss reduction savings. TPAG has reviewed this work and concluded that there is potential for *up to* $10m in capitalised savings in losses within the distribution networks in the upper island regions[115].

Thermal capacity increase benefits

7.3.18 Given that existing point of service power factors are generally quite high in the upper island regions, the potential for achieving further thermal capacity increases within the regional distribution networks would appear to be limited. However, improving from 0.99 lagging to unity power factor gives a 1% capacity increase. Using the 'rule-of-thumb' of $1m/MW[116] for network augmentation could give:

a) For the UNI (approx. 2000 MW @ 0.99 power factor) a potential of up to 20MW (1%) increase in capacity (valued at a NPV of $20m).

b) For the USI (approx. 1060 MW @ 0.995 power factor) a potential of up to a 5MW (0.5%) increase in capacity (valued at a NPV of $5m).

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

Overall benefits

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

Conclusion on location price signalling

7.3.21 The TPAG concludes that introducing an efficient location price signal for investment in regional SRC equipment is viable and likely to provide benefits against the status quo option.

7.3.22 Option 1 would provide a location price signal for alternative asset investments, but only if customers were to enter into new investment agreements with Transpower. It has no advantage in this respect over the status quo option, which relies on the same mechanism.

7.3.23 Option 4 would provide an efficient location price signal for alternative asset investments by introducing a kvar charge on average reactive power drawn from the grid during RCPD periods. The kvar charge would be set at the LRMC of a grid SRC asset investment. In addition, option 4

[114] SKM ibid – page 4.

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

[116] Note that this rule of thumb estimate is applicable to transmission capacity. Distribution capacity would cost more than this, so the benefit estimate is conservative.

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

Efficiency consideration 3: unintended efficiency impacts

7.3.24 As has been noted previously, option 1 is unlikely to deliver any materially different investment behaviour from offtake transmission customers compared with the status quo.

7.3.25 By establishing an efficient price signal, option 4 is likely to incentivise efficient investment in SRC equipment by offtake transmission customers. Customers would face an efficient investment signal through the kvar charge. Distributors could also choose to pass a similar signal on to their end-use customers through distribution pricing.

7.3.26 With the introduction of a kvar charge, some costs would be shifted from those that pay the interconnection charge to those that would be subject to the new kvar charge.

7.3.27 With a kvar charge in place, significant investments in SRC equipment downstream of the point of service would have the effect of:

a) reducing the utilisation of existing grid SRC assets; and

b) deferring investment in future grid SRC assets.

7.3.28 The first effect could introduce unintended efficiency impacts under a kvar charge because any decreased year on year kvar charge revenue would be recovered from the interconnection charge and thereby shift costs between participants. At the limit, where all UNI and USI DTCs maintained average unity or leading power factor at their points of service, there would be no kvar charge revenue.

7.3.29 However, the kvar charge revenue levels indicated in Table 39 show that they are very small compared with the amount of interconnection charge revenue. In addition, in practical terms, existing grid SRC assets are unlikely to become stranded as a result of distributor and end-use customer investments in power factor improvements. The likely outcome is that they would simply defer future grid investments in SRC equipment.

Conclusion on unintended efficiency impacts

7.3.30 The TPAG concludes that:

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

Efficiency consideration 4: competitive neutrality

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

Conclusion on competitive neutrality

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

Efficiency consideration 5: implementation and operating costs

7.3.33 Option 1 is essentially the same as the status quo, and would incur a small regulatory cost in providing the necessary Connection Code amendment. The process to be followed in making such a change is set out in the Code at clauses 12.18 – 12.25.

7.3.34 As outlined in paragraph 7.2.29, option 4 relies on a substantially similar pricing mechanism to the existing interconnection charge. Advice from Transpower indicates an implementation cost in the range $0.4 – 0.6m. Ongoing costs should be a very small increment of the existing cost to provide transmission billing.

7.3.35 Offtake transmission customers may face higher capex costs per kvar than would Transpower if SRC equipment is installed within their distribution networks as a transmission alternative. They would presumably select this option only if the benefits more than offset the additional costs. The SKM report provides helpful budgetary costs for a variety of capacitor bank installation options[117] at 11 and 33 kV. An 11 kV pole-mounted, switched (SCADA-controlled) capacitor bank of 0.75 Mvar capacity would cost around $6 / kvar annually (c.f. $4 – $5 / kvar for grid-located capacitor banks from Table 39).

7.3.36 Thus, an additional $1 – 2 / kvar of additional cost should be attributed to option 4, which equates to $0.4m – $0.8m annually for 375 Mvar of capacity or $4m - $8m on a capitalised basis.

7.3.37 Offtake transmission customers would face minor incremental costs in processing kvar charge invoices and there would be a small regulatory cost involved in introducing the change into the Code.

Conclusions on implementation and on-going costs

7.3.38 The TPAG concludes that the implementation and on-going costs would be as follows:

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

Efficiency consideration 6: good regulatory practice

7.3.39 As was outlined in the background and problem definition discussion in this section, the review of reactive power arrangements was commenced in response to concerns expressed by electricity participants in relation to the minimum power factor requirements in the Connection Code that apply to the UNI and USI regions. Relying on the provisions in the Connection Code to allocate costs and initiate efficient investments in reactive support equipment is problematic because:

a) it requires that offtake customers in the UNI and USI regions maintain a power factor level that is not practically possible to comply with; and

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

[117] SKM ibid – Appendix A

7.3.40 The amended status quo option does not materially improve on the status quo. While the specific concern relating to the impracticability of arranging for exactly unity power factor at a point (or points) of service is somewhat mitigated by providing a range of power factors that would provide compliance, the broader concerns in respect of Transpower's inability to enforce compliance and the difficulties inherent in concluding multi-party new investment agreements, remain.

7.3.41 Accordingly, the TPAG considers that the amended status quo option does not resolve the regulatory failure identified in the problem definition.

7.3.42 The option of introducing a kvar charge is assessed in Table 40 against the good regulatory practice efficiency consideration.

Table 40 Assessment against good regulatory practice

Principle	Comment
Consistency between regulators	Following the Commerce Commission's December 2010 s52P determination in respect of distributor price path regulation, non-exempt distributors are no longer able to retain some of the benefits where they efficiently invest in transmission alternatives. See further discussion below.
Durability	Option 4 is expected to be durable because it is based on, and is conceptually similar to, options that have been consulted on previously and have received broad support, particular from those parties that would be most directly involved (being Transpower and offtake transmission customers).
Consistency over time	Introducing a kvar charge requires a change from the status quo. This option therefore introduces a regime inconsistency at the point of its introduction. However, once introduced, an LRMC-based kvar charge should provide an enhanced and stable environment for investment decision making in the provision of SRC equipment over time.
Consistency over whole grid	The kvar charge mechanism is proposed to apply only in the regions of the grid that are subject to voltage constraint, being the USI and UNI. The mechanism is thus consistent within those regions but is unnecessary for the foreseeable future within the voltage-unconstrained LSI and LNI regions. It is therefore inconsistent over the whole grid, and less consistent than was the case with the status quo option (because an additional mechanism would be introduced by option 4). See also the further comment at 7.5.4.
Wealth transfers and step changes in prices	An initial wealth transfer and price step could be expected in the transmission charges for offtake in the UNI and USI that have significant net reactive power draws from the grid in the RCPD period. Once certainty is provided that the charge is to be introduced, these parties will have an opportunity to evaluate and possibly undertake investments that would mitigate the price step change. Table 39 indicates that the kvar charge is relatively modest in the revenue it would collect when compared against the other transmission charge components and efficiency gains have been identified for the option.
Market fit	The proposed kvar charge is conceptually similar to and compatible with the existing interconnection charge.

Impact of the Commerce Act

7.3.43 The Commerce Act s52P determination that currently applies to Electricity Distribution Businesses (EDBs) is the 30 November 2009 determination with various amendments[118]. The 22 December 2010 Input Methodology determination also applies to EDBs. These two determinations treat transmission alternatives differently.

7.3.44 The Commerce Commission is currently consulting on amendments to the s52P EDB determination, including a proposal to align the treatment of transmission alternatives with that specified in the Input Methodology determination clauses 3.1.2 and 3.1.3. Decisions on the proposed amendments are to be made by 20 October 2011.

7.3.45 The Commerce Commission has advised that the proposed amendment to the current s52P determination will not allow EDBs any additional benefits from investments in Transmission alternatives, unless the EDB buys the investment from Transpower. Submissions received from Orion and the ENA on this matter are therefore correct.

7.3.46 The Commerce Commission has advised that it adopted the approach for transmission alternatives under the Input Methodology determination as there is no robust method to distinguish between efficient and inefficient investments (or distinguish between efficient EDB investments and inefficient transmission network by-passes, for example). It considers that EDB investments in reactive support should be treated like any other investment in distribution assets and is not planning to revise the Input Methodology.

7.3.47 TPAG remains of the view that an efficient investment in SRC equipment transmission alternatives should be provided for in the regulatory regime that affects offtake transmission customers and recommends that the Authority considers this further, including undertaking further consideration of improvements that can be made to the overall regulatory regime.

Conclusions on good regulatory practice

7.3.48 The TPAG concludes that:

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

7.4 Cost Benefit Assessment Summary

7.4.1 As noted in paragraph 7.1.9, the status quo arrangements are problematic for two reasons:

a) the status quo, relying solely on the absolute unity power factor requirements of the Connection Code for the UNI and USI regions is not possible to comply with; and

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

7.4.2 TPAG concludes that the combination of these two factors indicates a regulatory failure that, if not remedied, may lead to dynamic inefficiencies in the way that investments in SRC equipment

[118] The current version is titled '*Consolidated version of Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2010 (including all amendments as at 31 March 2011)*'.

are made. In addition, it may be possible to clearly identify the beneficiaries of static reactive compensation investments.

7.5 Application of CAP 3: Assessment against efficiency considerations using the status quo as a counterfactual

7.5.1 Table 41 compares the options assessed relative to the status quo. Where possible, quantified benefits and cost estimates are included. Positive values indicate an overall efficiency gain in total NPV terms. Where it is not possible to quantify the benefits, a tick represents an improvement relative to the status quo.

Table 41 Assessment of the SRC options relative to the status quo option

Efficiency consideration	Option 1: Amended status quo	Option 4: Amended kvar charge
2. Location Pricing (see para. 7.3.20)	$0	$10.5m to $35m
5. Implementation & on-going costs Billing system upgrade (7.3.34) Additional DTC capex (7.3.36)	 $0 $0	 -$0.4m to $0.6m -$4m to $8m
Quantified benefit (NPV 30yr)	**$0**	**$6.1m - $26.4m**
1. Beneficiary pays (7.3.9)	same	✓
3. Unintended price impacts (7.3.30)	same	same
4. Competitive neutrality (7.3.32)	same	same
6. Good Regulatory practice (7.3.48) 1. Consistency between regulators 2. Durability 3. Consistency over time 4. Consistency over grid 5. Wealth transfers 6. Price step changes 7. Market fit	all same	 X ✓ X X X (very small) X (very small) ✓
Qualitative Score	**X**	✓

Observations

7.5.2 The amended kvar charge option has the highest net benefit against the status quo option.

7.5.3 Possible wealth transfers and price step changes associated with option 4 are expected to be small and manageable in the transition period. Option 4 is rated as a negative in terms of consistency over time because it is a change from the status quo. It should be consistent over time in the future, however.

Further comment regarding consistency over the whole grid

7.5.4 This section considers only the USI and UNI regions, which are relevant to the regulatory failure being considered. Leaving the LSI and LSI regions with status quo minimum power factor requirements based on a mechanism that is demonstrably unenforceable raises a further question as to whether a regulatory failure also exists with respect to the prescribed minimum power factor (of 0.95 lagging) in those regions.

7.5.5 An alternative may be to consider application of the proposed modified kvar charge option across all regions. However, while there may be a case to consider whether a kvar charge approach, suitably modified, could be applied to the LSI and LNI, it is first necessary to understand whether (and, if appropriate, to what extent) a problem and/or a potential inefficiency exists. While this issue is not further considered in this paper, the following question seeks to elicit information from submitters.

7.5.6 Submitters identified no aspects of the assessment of the assessed options against the efficiency considerations that they disagreed with or were able to provide further information in respect of.

7.5.7 Meridian pointed out that the only downside to the recommended approach is the risk of stranded and duplicate investments. However they did acknowledge that this risk does not appear to be material compared to the overall benefits of the proposal.

7.5.8 In respect of the assessment of costs and benefits, submitters generally supported TPAG's assessment of the costs and benefits.

7.5.9 However, in its additional comments, Vector expressed the view that "the estimation of thermal capacity increase benefits in paragraph 8.4.18 is implausible. The supposed benefits rely on the assumption that power factor will improve from 0.99 lagging to unity in both the UNI and USI. Given the cost of making the necessary improvements to reach unity, this seems unlikely. The potential capacity benefit of $25 million should therefore be removed from the CBA. If it remains, it should be weighed against the likely cost of making the investments to achieve a unity power factor in the Upper North Island (UNI) and Upper South Island (USI). This cost has been estimated by SKM to be in the region of $60 million."

7.5.10 The CBA scenario developed was simply that the benefit of improving the power factor from current levels (0.99 for the UNI and 0.995 for the USI) to unity using distribution network located investments (as opposed to grid located investments) includes a distribution network capacity benefit of 1% (UNI) and 0.5% (USI) and a distribution network loss reduction benefit. The cost of obtaining the *incremental* benefits is just the cost of implementing the incentive mechanism and the *incremental* cost of distribution network investments over equivalently rated grid located investments (the $60m cost that SKM proposed applied to a different scenario).

7.5.11 The scenario selected for the CBA does not imply that improving the power factor to exactly unity is the *optimal* investment. All parties acknowledge that an optimal level of investment in power factor correction equipment is likely to be "very near but just below unity", possibly in the region of 0.998 to 0.999 lagging. The selection of unity in the CBA simply makes the cost-benefit ratio conservative and avoids having to estimate what an "optimal" level might be.

7.5.12 The TPAG is not concerned with finessing the level of optimal investment, as the outcome cannot be exact and the price incentive mechanism simply sends an approximate price signal. Thus, having considered submissions, the TPAG is comfortable with its analysis of the options against the efficiency considerations.

7.5.13 In respect of questions relating to the consistency of approach across all regions, submitters' views generally reflected two schools of thought. Firstly, a group of submitters supported retention of minimum power factor level in the Connection Code, per the status quo. Comments made in support of this view included the observation that even if the minimum power factor level proved to be unenforceable as a practical matter, at a minimum it provided a clear signal of a regulatory expectation and, as such, there was a benefit in its retention.

7.5.14 The alternative view was that regime consistency across all regions should be the primary goal and that the solution adopted for the UNI and USI regions should apply equally to the LNI and LSI regions.

7.5.15 MRP felt that the penalty charge was appropriate across all regions for power factor below a set minimum but that the kvar charge mechanism was not appropriate for the LNI and LSI regions.

7.5.16 As discussed earlier when considering the feedback on the related question regarding retention of a minimum power factor, TPAG is comfortable recommending retention of a minimum power factor in the Connection Code that is set at a nationally consistent level of 0.95 lagging.

7.6 Consideration of other points raised in submissions

7.6.1 A number other views were provided in submissions of the TPAG's Discussion Paper. These views have been considered by TPAG; the more significant comments are outlined in this section along with the TPAG's responses.

7.6.2 Vector felt the Discussion Paper contained an implicit assumption that unity power factor was achievable and was a desirable objective. In this respect, it felt it was "crucial to understand Transpower's objective [so as] to understand the cost implications of this proposal. If Transpower sought to signal the cost of achieving a power factor of unity then the LRMC of the proposed new assets would equal the cost of achieving unity power factor, which would mean the kvar charge would be very high …". In Vector's view "it will be optimal for power factor to be slightly below unity for all direct transmission customers …" and this must be recognised. Orion expressed a similar view in respect of unity power factor.

7.6.3 The TPAG has not sought to express a view that unity power factor is a desirable objective. It agrees with Vector and Orion that a power factor near unity will likely be optimal in terms of overall investment efficiency and believes that the amended kvar charge methodology is consistent with such an outcome. As was discussed earlier, the kvar charge as an incentive mechanism sends an approximate price signal and further analysis that might seek to finesse an optimal level of investment is not warranted.

7.6.4 Two submitters expressed views that DTCs with net leading power factors during RCPD assessment periods (i.e. those exporting reactive power into the grid) should be paid or otherwise appropriately compensated for that service. Pan Pac's view implicitly extended to consideration of this point in respect of power factor management in the lower island regions, given that the Pan Pac Forest Products Ltd plant is connected to the grid in the LNI region.

7.6.5 While there may be a case to consider some closely located DTCs for equivalence provisions (an obvious example is Counties Power and NZ Steel that share a GXP at Glenbrook), TPAG has not considered this aspect in detail at this point.

7.6.6 At this stage of development, the TPAG is suggests that:

a) net power factor is assessed on a customer by customer basis, so that a DTC having a poor power factor at one GXP may internally compensate this with a good power factor at another of its GXPs; but

b) further consideration of equivalencing reactive power between different DTCs is undertaken by the Authority.

7.6.7 Orion expressed “significant concerns in regard to the use of the RCPD as an appropriate cost allocator.” In its view “the RCPD [periods] are determined after the event and provide only a very limited signal as to when reactive power may be required, i.e. RCPD usually occurs in the USI during the winter months this effectively means EDBs and customers will have to minimise their kVAr off take at all times.”

7.6.8 The point here appears to be that the actual RCPD periods are not known with any degree of certainty as a winter period progresses, keeping the pressure on DTCs throughout the winter period to minimise their reactive power demand. The TPAG’s view is that this should not be an insurmountable issue for DTCs to manage – RCPD periods are relatively predictable within broad time zones and the key decisions required of DTCs are longer-term decisions, including investment decisions, as opposed to operational decisions. In operational timeframes, available controllable reactive power resources are very likely to be in operation during RCPD periods in any case so as to support network voltages.

7.6.9 Orion submitted further that “the current RCPD 50 hour assessment period for the LSI and LNI versus the 6 hour assessment period for the USI and UNI disproportionately allocates Transpower’s revenue requirement between upper and lower island regions. The introduction of a kvar charge in the USI and UNI further increases the subsidy between upper and lower island regions. The Authority should give consideration to how this allocative issue (subsidy) can be addressed whilst still providing the correct investment incentives.”

7.6.10 TPAG’s view is that this is not an issue for it to consider in respect of it considering the reactive power regulatory failure but may be an issue the Authority may wish to further consider more generally.

7.6.11 Powerco and The Lines Company both commented in respect of the impact on DTCs that have significant embedded generation. In Powerco’s view, embedded generation is an important consideration for power factor management that was not discussed in the paper. It submitted that “is not clear how embedded generation would be treated by the options outlined in the paper and given the likely proliferation over the medium term [it] should at least be discussed.”

7.6.12 The Lines Company commented similarly on the impact that distributed generation can have on grid point of connection power factors. Its view is that “points of service nationally that have significant distributed generation connected have a lower power factor.” The concern this raises is that “the proposed changes to the connection code with a .95 power factor trigger for reactive charges will disadvantage and cause greater costs for distributors with distributed generation connected.”

7.6.13 TPAG’s view is that embedded generation that has been designed to provide adequate local network voltage support should potentially assist a DTC in meeting its GXP requirements in respect of reactive power. Synchronous generators and compensated induction generators should make a DTC no worse off from a net GXP reactive power perspective than it would have been without these generators. While the observation that points of service nationally that have significant distributed generation connected have a lower power factor may well be a valid historical observation, any larger generators will generally provide the operating capability to improve net GXP reactive power flows.

7.6.14 Net offtake reactive power at RCPD periods drives the proposed new reactive power offtake charge; power factor is only proposed to provide a minimum level via transmission contracts, as has been the case for many years. Thus, DTCs with significant embedded generation in the networks should be no worse off that they would have been under previous arrangements.

7.7 Recommendation

7.7.1 The analysis in this section supports the introduction of a kvar charge, as developed as option 4, within the TPM[119].

7.7.2 Near unanimous support was expressed in submissions for the proposed approach of the amended kvar charge, with a few caveats, minor refinements suggested and questions posed for TPAG's consideration.

7.7.3 Accordingly, TPAG recommends that the Authority:

a) amend the Guidelines published under clause 12.83 of the Code to provide that the TPM should include a reactive power off-take charge based on a $/kvar rate;

b) amend the Connection Code in Schedule 8 of the Benchmark Agreement to remove the unity power factor requirement for the Upper North Island and Upper South Island regions and to replace this with a measure that aligns the upper region power factor requirements with the 0.95 lagging minimum that currently applies to the Lower North Island and Lower South Island regions; and

c) further consider the issues raised around alignment of the proposed pricing mechanism with the Commerce Act in respect of regulated distributors and works with the Commerce Commission to determine what improvements might be made.

Implementation

7.7.4 The TPAG observes that implementing a kvar charge would require the following Code amendments:

a) Changing the minimum power factor requirement in the Connection Code (Schedule 8 of the Benchmark Agreement) for the UNI and USI regions so as to align them with the LNI and LSI regions. Specifically, it is proposed that the process set out in the Code at 12.18 – 12.25 is followed. It is proposed that clause 4.4 (minimum power factor) is amended as follows[120]:

4.4 Minimum power factor

*(a) If **electricity** is being drawn off the **grid**, the Customer must maintain a Power Factor of not less than 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period.*

(b) For the purposes of this clause:

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

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

(1) *the regional peak demand periods and regions are as defined in Schedule F of the* ***transmission pricing methodology****; and*

(2) *the relevant regional peak demand period is the regional peak demand period for the region in which the Point of Service is located.*

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

7.7.5 In relation to amending the Connection Code, this would require that the process set out in the Electricity Industry Participation Code at clauses 12.18 – 12.25 is followed. As the Connection Code is incorporated by reference into the Code, the Authority would also need to comply with Schedule 1 of the Act.

7.7.6 In relation to amending the TPM in schedule 12.4 of the Electricity Industry Participation Code, the Authority must comply with the Electricity Industry Act (in particular section 39, which sets out the process for amending the Code), as well as the applicable provisions of the Code in relation to making changes to the TPM.

7.7.7 The annual reactive power offtake charge would require specification of the following items:

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

b) Its unit of measurement, being net average offtake reactive power per customer in kvar.

c) The time period used for its assessment, being the regional coincident peak demand (RCPD) for a customer at a customer location.

d) Guidelines setting out the methodology to be used in establishing the annual $/kvar charge rate, based on assessing the replacement capital and operating costs of a grid capacitor bank (or a group of banks of different sizes and voltages).

e) Guidelines setting out the methodology to establish the expected reactive power offtake revenue, this revenue to be offset against the interconnection revenue requirement.

8 Summary of recommendations

8.1 HVDC Cost Allocation

8.1.1 TPAG recommends that the Authority:

a) consider the analysis undertaken by TPAG on the possible efficiency losses associated with the current HVDC charges;

b) complete a GEM analysis to cross-check the size of the efficiency losses calculated by TPAG; and

c) determine whether it agrees or not with either of the following alternative views:

View 1: the HVDC cost allocation should be changed to a postage stamping with a 10 year transition arrangement because:

- the efficiency losses from the HVDC charging regime are material; and
- it is not possible to clearly and objectively identify the beneficiaries of the HVDC link and the extent of their benefits. Beneficiaries are likely to change over time and objective identification of specific beneficiaries may be difficult and problematic.

View 2: the status quo should prevail because:

- the estimates of the efficiency losses have wider error bounds than the analysis shows due to factors not captured by the analysis. In light of this, it is plausible that the efficiency losses may be closer to zero (that is, not significant);
- the estimates of efficiency gains from a transition to postage stamping are uncertain because they are measured against a counterfactual of lower long run marginal cost (LRMC) of generation than implied by the status quo;
- in contrast, the shifting of HVDC charges from SI generators to off-take customers is a certainty. Under the transition to postage stamping arrangement customers will experience a certain increase in cost and an uncertain benefit; and
- it is possible to identify that the SI generators are the primary beneficiaries; other participants may derive some benefits, but these are insufficient to argue that they should pay for the HVDC.

8.2 Connection Charges

8.2.1 TPAG recommends that the Authority:

a) note TPAG's view that the evaluation of deeper connection options cannot be completed until the Transpower CapexIM is determined by the Commerce Commission under section 54S of the Commerce Act 1986; and

b) consider engaging with the Commerce Commission to explore further the extent to which benefits might accrue if there is a deeper allocation of costs to customers and the possible mechanisms for implementing such a change.

8.3 Static Reactive Compensation

8.3.1 TPAG recommends that the Authority:

a) amend the Guidelines published under clause 12.83 of the Code to provide that the TPM should include a reactive power off-take charge based on a $/kvar rate;

b) amend the Connection Code in Schedule 8 of the Benchmark Agreement to remove the unity power factor requirement for the Upper North Island and Upper South Island regions and to replace this with a measure that aligns the upper region power factor requirements with the 0.95 lagging minimum that currently applies to the Lower North Island and Lower South Island regions; and

c) further consider the issues raised around alignment of the proposed pricing mechanism with the Commerce Act in respect of regulated distributors and works with the Commerce Commission to determine what improvements might be made.

Appendix A Analysis supporting the assessment of HVDC cost allocation options

A.1 Introduction

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

- the potential generation investment inefficiency caused by the HVDC cost recovery potentially delaying cheaper SI options relative to North Island options of the next 30 years;
- the competitive detriment from Meridian having an advantage over other SI generators or new entrants;
- potential value impact to end use customers from a shift of HVDC cost recovery from SI generators to customers; and
- the potential peaking generation investment inefficiency caused by the HAMI-based charge.

A.2 Methodology for assessing possible generation investment inefficiency

A.2.1 The potential generation 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 use 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).

A.2.2 This appendix describes a simplified analysis[121] of the possible increase in present value of future new generation investments arising from the HVDC charge using the following methodology:

- A simple merit order of new generation base load and renewable investments[122] is constructed by making assumptions about the capital costs, fuel costs, plant efficiencies, and operating costs of various plausible power station options[123];
- The new generation investments are ranked on the basis of a simple long-run marginal cost (LRMC) measure including capital recovery, fixed and variable operating costs, fuel and Emissions Trading Scheme (ETS) costs, and approximate location factors (reflecting marginal losses) and intermittency factors[124;]
- 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;

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

[122] The analysis focuses on base load and renewable generation options as these are the options that are most likely to be significantly affected by the HVDC cost recovery. The impact on new mid merit and peaking investment in the SI is discussed in a later section. The analysis assumes that the demand for new 'baseload' capacity is driven by energy demand (GWh) plus a modest allowance relating to the retirement of existing NI thermal plant. This is believed to be a conservative assumption as the expected increases in carbon and gas prices, and gas supply restrictions is likely to result in existing CCGT and coal plant moving into a less base load and more a mid-merit role, and thus increased demand for these 'baseload' options.

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

[124] The LRMC used here is the levelised average real time-weighted average future price at Haywards necessary to cover the full costs of the new investment option being considered over its life-time.

- The potential economic cost is estimated by calculating the increase in present value cost between the two scenarios for a number of different scenarios.

A.2.3 The analysis described in the appendix only considers generation options that can be accommodated within the committed capacity of the HVDC[125]. It does not consider, or attempt to quantify, the possible benefit of co-optimising, deferring or preventing investment in a new or expanded HVDC link[126], or the possible benefit of deferring AC transmission upgrades necessary to support an expanded HVDC link. New transmission investments are approved by the Commerce Commission on the basis of a national cost benefit analysis which will trade off the costs of new transmission against the benefits in terms of improved supply reliability or cost. The possible link between the TPM cost allocation and the efficiency of these future transmission investments is discussed in sections 5.6.2 and 5.10.2 in the main body of this report.

Reasons for focusing on base load and renewable options

A.2.4 The Biggar Report correctly points out that there will actually be a mix of peaking, mid merit and baseload, whereas the simplified analysis in this appendix focuses on only base load and renewable generation options. The reason for focusing on base load and renewable is that these options are most likely to be significantly affected by the HVDC cost recovery.

A.2.5 The analysis assumes that the demand for new baseload capacity is driven by energy demand (GWh) plus a modest allowance relating to the retirement of existing NI thermal plant[127]. This is likely to be a conservative assumption given that the expected increases in carbon and gas prices, and gas supply restrictions are likely to result in existing (or replacement) CCGT and coal plant moving from a base load to a more a mid-merit role over time. This is likely to lead to an increased demand for base-load and renewable options.

A.2.6 A significant amount of new peaking and mid-merit plant is likely to be required in the future. However the HVDC charge is not expected to have a significant impact as most of this is likely to

125 The modeling assumes a maximum average South to North energy transfer of 5250 GWh per year to account for hydro-driven variations.

126 The Biggar Report appears to have the mistaken impression that this analysis was assessing the full welfare impacts of the HVDC cost allocation, whereas it is not addressing issues related to transmission investment efficiency. In submissions Genesis raised the concern that the analysis did not include any scenario where future HVDC investment is required even though this is a plausible scenario. This appendix deliberately excludes this scenario as it is focusing on potential impact of the additional locational signal arising from the combination of the HVDC charges, nodal market prices and the committed transmission investments approved under the GIT.

127 This analysis focuses on the demand for base load and renewable options which will be driven vy the path of 'peaking factor' adjusted time weighted average spot and contract prices. The demand for other peaking and mid merit options will be driven by market option values (i.e. the net value of an option contract with a strike price equal to the peaker or mid-merit generator's short run marginal cost). The mix of different types will depend on the relative fixed and variable costs of this different base load, mid and peaking options. In New Zealand there is likely to be a relatively high demand for pure peaking plant (driven by peak demand growth and increasing supply from wind). This is likely to be met from new peaking plant located in the NI, and not significantly impacted by the HVDC cost recovery since, as a rule there is no likely advantage in building such capacity in the SI given that the capital cost is equivalent, there is no gas available in the SI and there is a marginal loss (and possibly) a transmission constraint disadvantage. However there is likely also to be an increasing demand for renewable and baseload capacity. This reflects both growth in demand for energy and the likely reduction in the energy contribution from existing thermal plant which have been operating at a reasonably high capacity factor but which are likely to be retired or operated in a reserve or mid merit mode as gas and carbon prices are expected to increase significantly in most scenarios. The expected high gas, coal and carbon prices mean that the cost of running existing or new thermal plant in base load mode is greater than the cost of many renewable options such as geothermal, hydro and wind. In New Zealand there is a rising cost curve of these options (both nationwide and in each island) and the development of these options may be impacted by the HVDC charge.

be focused in the NI (even without an HVDC charge) as capital costs are likely to be similar, gas is more available and there is likely to be marginal loss and constraint benefits. The HVDC charge may have a small impact on a limited amount SI peaking capacity associated with new hydro and wind options or from existing hydro upgrades. This is discussed further in section A.15.

Accounting for variability in renewable wind and hydro options

A.2.7 While thermal plant can operate in a range of modes from peaking, through mid-merit to baseload, the LRMC measure used here is based on its operating in baseload mode (with a capacity factor equal to its expected annual availability accounting for planned and random outages). Empirical 'peaking factors' are used to account for the variability in hydro and wind renewable options[128].

A.2.8 The peaking factor is the ratio of the generation weighted-average prices (GWAP) relative to time-weighted average prices (TWAP). These peaking factors can be used to adjust the value of average energy output from these schemes so they can be ranked against genuine base-load options such as geothermal. A genuine base load option such as geothermal can be expected to earn the time weighted average market price, whereas a renewable option such as wind or hydro will achieve generation weighted average revenues which are either higher or lower than this depending on the extent to which their output can be controlled (in the case of hydro) and the variation and correlation of their output with market spot price.

Wind peaking factors

A.2.9 Historical peaking factors are 93-94% for the existing correlated NI wind sites and around 100% for small uncorrelated SI sites. These factors are expected to be less than 100% given that wind generation is correlated and cannot be fully relied on to contribute during periods of capacity scarcity (i.e. if there is enough correlated wind on the system that capacity scarcity can, from time to time, be caused by combinations of low wind and high demand). For this analysis it is assumed that peaking factors for new wind in both islands fall to 92-90% as the percentage of wind generation on the system increases.

A.2.10 Another way of deriving the peaking factor for wind is to look at the cost of additional peaking capacity necessary to back-up the average level of generation to a base load equivalent. The Electricity Commission estimated that wind contributes a conservative 20% on average of its capacity during periods of peak supply risk[129]. If a wind farm is assessed on the basis of a 40% average capacity factor, then it would need to purchase 20% backup capacity to be equivalent to a normal base load plant. The cost of this is estimated to be approximately $8/MWh (50% of the cost of an oil fired peaker = $145kW/yr or $16/MWh base load). The base load equivalent of wind is thus $8/MWh, or around 8-9%, lower than the cost of new wind costing $95-$100/MWh on average. This is also consistent with the 92% to 90% peaking factor used in the analysis.

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[128] The Biggar report recommended that an adjustment be made to account for this, but failed to realise that these adjustments were already included in the analysis.

[129] See "Statement of Opportunities", September 2010 page 92. As discussed here the 20% contribution was derived using statistical techniques to convolve the output of wind generators with demand and the availability of plant from the rest of the generation stack. This contribution factor is yet to be firmly established and more recent analysis by the Commission and others suggest that this could be 30% for moderate levels of wind penetration.

Hydro peaking factors

A.2.11 The peaking factors for run of river and partly peaking hydro reflect the amount of hydro storage available and the volatility and correlation of inflows. This can vary from project to project, however historical peaking factors for the total Waitaki scheme (100%), Clyde and Roxburgh (91%), Waitaki station (96%) and Branch (93%) provide an indication of the level expected in the future. The Waitaki scheme has significant storage and peaking capability, yet only achieves a 100% peaking factor due to its high correlation with total SI inflows and prices. Clyde and Roxburgh have moderate peaking capability, high correlation and limited medium term storage and hence only achieve 91%. Branch is a run of river scheme with very limited short term storage, but lower correlation and achieves a 93% peaking factor. New SI run of river hydro are assumed to have peaking factors similar to Branch (around 92%-95%), and new peaking hydro on the Clyde and Waitaki rivers are assumed to have peaking factors similar to Roxburgh and the Waitaki Power station (91-96%).

A.3 Constructing the merit order

A.3.1 There is a merit order of future new generation projects that are available to meet the growing demand for electricity. It is difficult to know exactly what this merit order is because it depends on a range of factors (capital and fuel prices, resource availability, exchange rates, and discount rates, for example). Many factors influence the sequence of development for new generation, but it is reasonable to assume that new projects generally proceed according to a rough order of cost with the cheapest projects proceeding first.

A.3.2 For this analysis it is not especially important what the exact merit order is[130]. What is important is the potential cost of changing the merit order though the application of HVDC charges on SI generation projects.

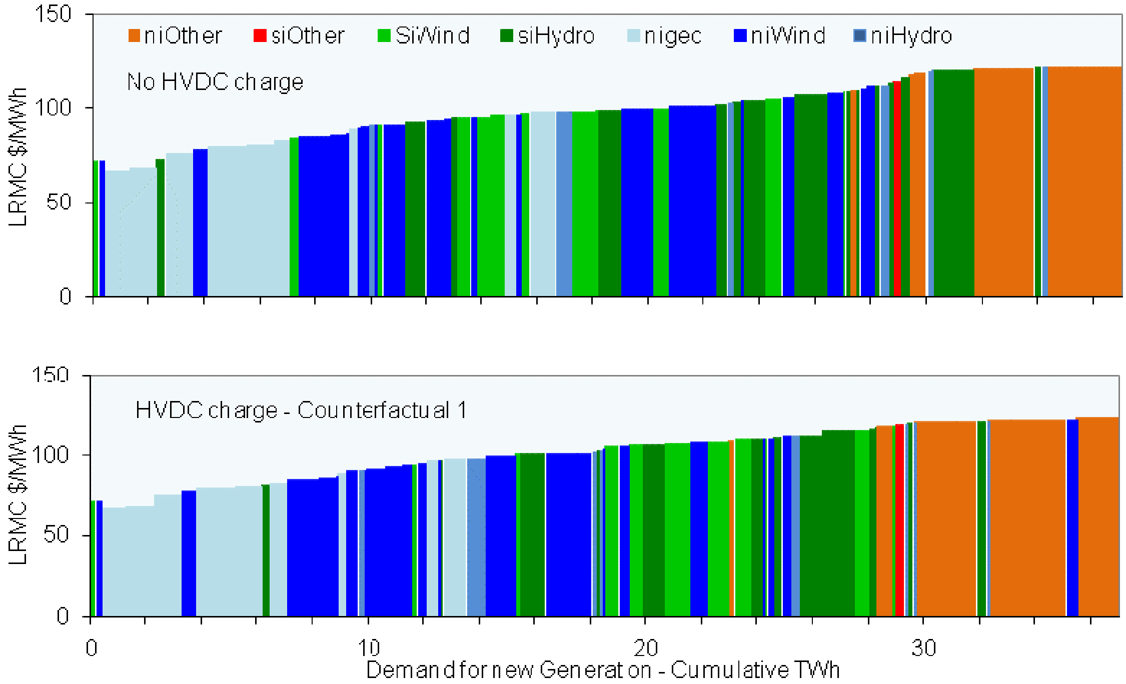
A.3.3 Figure 13 illustrates the two different merit orders used in this analysis, highlighting that a range of geothermal and wind projects appear to provide the cheapest development options[131]. Note that 10TWh represents approximately 25% of today's annual electricity demand.

A.3.4 The potential impact of the HVDC charge on the merit order is illustrated by the change in the charts in Figure 13 . In this example, a number of SI wind and hydro projects are delayed as a result of the HVDC charge.

[130] Note that this simplified approach is considered reasonable, since the aim is not to accurately predict the actual timing of new development plan in detail, but rather to predict the impact of the HVDC charge on the development plan (ie on the relative timing of NI and SI baseload and renewable options).

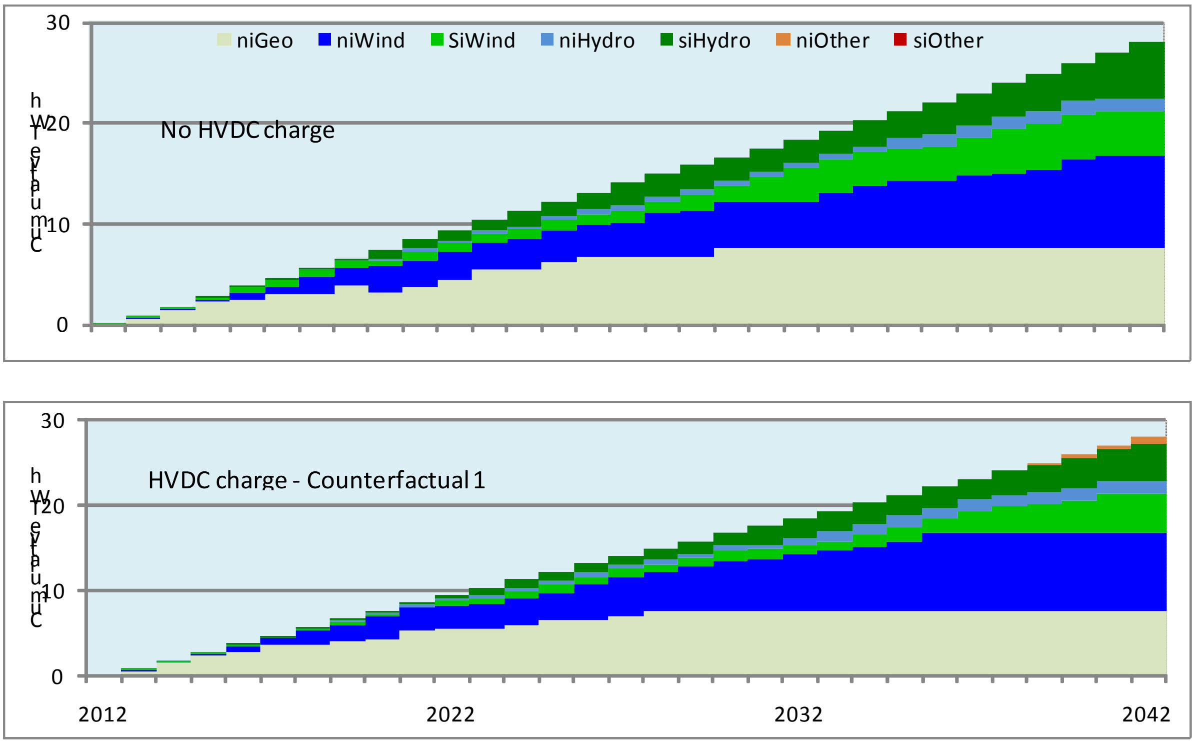
[131] The LRMCs have been estimated using a weighted-average-cost-of-capital (WACC) of 7% real post-tax. This reflects a typical nominal commercial post-tax rate of return required by generators adjusted for inflation.

Figure 13 Illustrative merit order of new generation projects ($/MWh)



A.3.5 This is further highlighted in Figure 14 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.

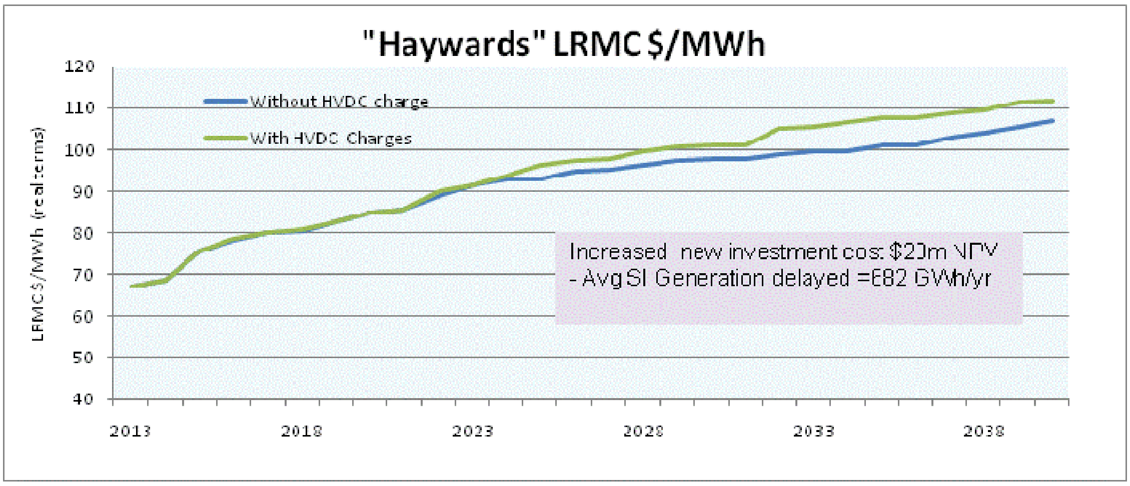
Figure 14 Illustrative impact on timing of investment



A.3.6 Figure 15 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 an assumed average location factor for each project.

A.3.7 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. This chart shows the illustrative impact of the HVDC on national LRMCs and prices at Haywards. It is possible that the lowering of LRMCs in the SI may have a more significant and earlier impact on SI wholesale prices. This is discussed in section A.14.7 below.

Figure 15 Impact on the LRMC curve



A.4 Scenario and sensitivity analysis

A.4.1 An estimate of the economic cost has been determined by calculating the difference in the net present value of investment between the two scenarios over 30 years using a 9% real pre tax discount rate[132].

A.4.2 The analysis of economic costs is dependent on a number of assumptions including; new investment costs, fuel costs and availability, exchange rates and other factors. These cannot be known with certainty in advance and so a combination of scenario and sensitivity analysis is used in the analysis.

A.4.3 A standard scenario approach is used to account for the impact of alternative 'states of the world'. However the impact of an HVDC charge also depends on the relativity between individual renewable projects such as wind and hydro. These will vary significantly from site to site depending on; the quality of the resource, the cost of connection to the grid, the resource consent limits and the international costs of generators and turbines at the time that these projects are committed. These cost variations cannot be known and will only become apparent during the process of project investigation, planning and resource consenting.

A.4.4 Each scenario uses a list of potential projects that was developed by the Commission for the Statement of Opportunities (SOO) published in September 2010 and used by the Ministry of

[132] 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.

Economic Development in its Energy Outlook published in December 2010. This list of potential projects has been developed over a number of years and has been consulted on and used in modelling work for transmission investments and other electricity sector issues.

A.4.5 The list of projects includes around 960MW of NI geothermal, 2900MW of NI wind and 1360MW of SI wind, 470MW of NI hydro and up to 2240MW of SI hydro, 310MW of NI cogeneration and 42MW of SI cogeneration. Much of the hydro is relatively high cost. It also includes a number of NI gas-fired thermal options which may be viable if there is sufficient local gas available as a reasonable cost. Additional coal fired options are also possible based on SI, NI or imported resources and may be viable if coal prices and carbon prices are low enough, but this is not considered likely. There are numerous peaking options, but these are not used in this analysis as it focuses on new projects to meet the demand for 'energy' rather than peaks. The typical level of costs of these projects and the earliest commissioning has been updated to reflect more recent information.

A.4.6 Exchange rates are assumed to revert to long run averages, 0.6 for the USD:NZD cross rate and 0.5 for the Euro:NZD cross rate. With this assumption, the typical real 2010 capital cost levels are assumed to be; $2300 to $2500/kW for wind, $3000 to $6000/kW for hydro, $4700 to $5200/kW for geothermal, $1750/kW for CCGTs and $3000/kW for coal. In addition to these generic costs, the costs of connection[133] are included.

A.4.7 As discussed above, all these costs are subject to considerable uncertainty. This is accounted for by randomly sampling project capital by ± 20% around a generic capital cost for each general class of investments (geothermal, wind, hydro, thermal etc). This random adjustment to capital costs can also be considered as a proxy for the range of other real world factors which a number of submitters has suggested might influence investment decisions (such as resource quality and consent issues, option values arising from non-anticipatively of external risks, portfolio issues, connection costs and losses etc).

A.4.8 In each scenario it is assumed that there is a significant amount of cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. As pointed out by some submitters, geothermal and hydro projects are subject to significant resource consent risks. This is accounted for in the scenarios below by limiting the total MW of each type of technology available over the next 30 years.

A.4.9 In response to submissions from MEUG and others, this analysis has been applied to each of the five SOO scenarios which are considered to be equally likely. It is not possible to replicate all of the features of these scenarios with this simplified approach; however the key features likely to be important for this analysis have been accounted for. These are listed in Table 42.

[133] This includes all uncommitted deep and shallow transmission costs necessary to accommodate these projects. It excludes committed capital expenditure such as the lower south island facilitating renewables project.

Table 42 Key scenario parameters

	\$/GJ	\$/t	Limits on new development (MW)				Peaking Factor		
Scenario	**Gas**	**CO2**	**Geo**	**HydPk**	**HydRR**	**Wind**	**Wind**	**HydRR**	**Notes**
1. Sustainable path	\$23	\$60	750	1,170	1,310	4,000	0.90	0.95	Extra thermal closures
2. SI wind	\$18	\$50	500	1,020	1,150	4,000	0.90	0.95	Extra thermal closures
3. Med renewables	\$13	\$30	750	830	440	4,000	0.90	0.95	Tiwai phases out: 10yr from 2025
4. Coal	\$13	\$20	750	500	120	4,000	0.92	0.95	
5. High gas discovery	\$8	\$40	500	820	440	4,000	0.92	0.95	

A.4.10 In all but the high gas discovery scenario it is assumed that gas supply remains limited and the coal price is \$4.5/GJ in real 2010 terms. Under these scenarios, the existing CCGT capacity is maintained or refurbished and most new baseload capacity is geothermal, hydro or wind over the next 30 years. Thermal plant is assumed to be too expensive and only operates in a mid-merit or peaking role.

A.4.11 The high gas discovery scenario is based on an assumed increased supply in natural gas at \$8/GJ (real) sufficient to support some additional CCGT gas plant beyond 2025 in the NI.

A.5 Cost of HVDC charges to incumbent SI generators

A.5.1 It is assumed that the average net HVDC cost under the existing price structure is \$35/kW/yr in real 2011 dollar terms[134] for the 15 years following the commissioning of pole 3 if SI generators continue to receive the value of HVDC rentals.

A.5.2 While this \$35/kW/yr HVDC cost represents the disincentive for new entrant generators in the SI, incumbent generators may not suffer the same level of disincentive. This is because total HVDC charges are fixed and any new investment in SI generation will result in a reallocation of the charges between the incumbent generators and new generators. A completely independent new SI generator will see the full incremental HVDC cost for its new generation (\$35/kW/yr), but the incumbents will benefit from a reduction in their share of the costs. The extent to which large incumbent generators have an advantage relative to new entrants depends upon both its share of the HVDC costs and the investment 'counterfactual' which applies.

A.5.3 Under counterfactual 1 it is assumed that new SI investment by an incumbent SI generator would displace other similar SI generation. In this case the SI incumbent will benefit from reduced HVDC

[134] In reality the gross HVDC charge (in real 2011 terms) is expected to be around \$45/kW/yr in 2013, falling to around \$40/kW/yr by 2020, and then continuing 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.

charges regardless of whether it or a competitor builds new generation, and it can be demonstrated that the incremental HVDC charge it would face, in respect of the new generation, would be the same as that of its competitors.

A.5.4 Under counterfactual 3 it is assumed that new SI investment by an incumbent SI generator would not displace other similar SI generation. In this case the SI incumbent will benefit from reduced HVDC charges if it proceeds with the new generation and it will have an advantage relative to small incumbents and new entrants.

A.5.5 In practice, one cannot be certain about what would occur in the absence of a new investment by one of the incumbent SI generators, and different incumbents are likely to make different assumptions about what is likely and what their cost relative to a competitor's cost will be.

A.5.6 It can be shown[135] algebraically that the incremental HVDC cost for an incumbent investing in the South Island is somewhere between 100% of the full HVDC cost ($35/kW/yr) and (100% less its existing cost share[136]) times the full HVDC cost, depending on the investment counterfactual. Counterfactual 2, lying between the two extremes, has therefore been developed for the purpose of this analysis.

A.5.7 The potential counterfactuals and the impact on the largest incumbent (Meridian Energy with 69% share of HVDC charges following the transfer of Tekapo) are described in section A.9 below.

Table 43 SI generation investment counterfactuals and impact on Meridian Energy

Option	Description	Meridian's net incremental cost from HVDC charge
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%-69%)*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 counterfactual 2 it has been assumed that the cost impact is half way between the two extremes.	$23/kW/yr

A.5.8 The generation investment inefficiency depends on which of these counterfactuals the incumbents use in their commercial decision-making and which projects they might be able to develop. In its submission, NZIER suggests that Meridian should be able to develop all new SI projects at the same cost as any other developer and that the appropriate counterfactual was 3

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

136 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 69% for Meridian, 22% for Contact, 6% for Genesis and 2% for TrustPower.

(i.e. none of the projects that it developed would crowd out investment by others). On this basis, NZIER claimed that the investment inefficiency would be less than $10m NPV.

A.5.9 However this is not a reasonable assumption for the following reasons:

- It is unrealistic to expect that Meridian would be able to develop projects such as hydro on the Clutha (where Contact has land and synergies with other plant on the same river chain), or projects such as Arnold, Wairau, and Mahinerangi where TrustPower has resource consents and land ownership.
- It is unrealistic to expect that Meridian would have the interest or capability to develop all the SI opportunities as efficiently as the market where a range of incumbents and new entrants are in full and equal competition.
- It is more realistic to expect that if Meridian were to develop all these options, Meridian would assume that investments by others in the SI would be crowded out as a consequence. This would imply that it would use an intermediate counterfactual (such as Counterfactual 2) in its investment decision-making.

A.5.10 TPAG accepts that the assumption used in the earlier analysis (Counterfactual 1) overstates the generation investment inefficiency, but notes that this was used as an alternative to separately assessing the competitive detriment of Meridian's competitive advantage. TPAG believes that a reasonable basis for assessing the generation investment inefficiency is Counterfactual 2 combined with an assumption that Meridian can develop 50% of the generic new SI projects (excluding Clutha Hydro, Arnold, Wairau and Mahinerangi stage 2). The impact of alternative assumptions is explored later.

A.5.11 When this approach is taken the additional competitive detriment from Meridian increasing its dominance in the SI needs to be accounted for. This is addressed in section A.14.

A.6 Generation investment inefficiency with HAMI cost allocation

A.6.1 TPAG has updated the earlier estimates for the additional generation investment cost arising from the HVDC cost allocation using these revised assumptions for each of five different scenarios which reflect the key drivers used in the 2010 SOO. The results are reported in Table 44.

Table 44 Generation Investment inefficiency with a HAMI charge- Scenario Analysis

Additional "baseload" investment cost $m NPV				
	Average	**Min**	**Max**	**Std dev**
1. Sustainable Path	$22	$10	$40	$10
2. SI Wind	$23	$10	$39	$8
3. Med Renewables	$21	$14	$38	$8
4. Coal	$24	$14	$36	$9
5. High Gas Discovery	$31	$15	$48	$10
Average/Min/Max/Std dev	**$24**	**$10**	**$48**	**$9**

A.6.2 The analysis undertaken for a $35/kW/yr HAMI cost suggests an economic cost in a band of $10m to $48m (average $24±9m)[137]. The average assumes an equal probability weight for each scenario. The minimum, maximum and standard deviation reflects the variation over sensitivities where the capital cost for individual new projects is randomly varied within a +/- 20% range around the expected level for each technology type.

A.6.3 The lower end of the range of the economic cost applies in sensitivities where there is a large quantity of NI generation options that have a lower cost than SI options and hence the HVDC cost allocation does not have a significant impact for a number of years. In all cases it is assumed that there is a significant amount of relatively cheaper NI geothermal which is likely to meet most of the demand growth over the next 5-10 years irrespective of the HVDC charge. Hence the lower levels of economic cost arise from there being a significant block of cheaper NI wind. Note that approximately twice as much potential wind is assumed to be available in the NI as in the SI and hence there is the potential for a delay in the impact of the HVDC charge if much of this NI resource is cheaper than the SI. The relatively low cost in scenario 3 reflects the assumption that Tiwai is phased out and hence SI options can be more likely constrained by the existing capacity on the committed HVDC link.

A.6.4 The upper range of economic cost applies in other sensitivities where there are some SI options which are of a similar or lower cost to NI options and hence the HVDC cost allocation results in a much more significant delay from an earlier date. This can also occur in the scenario where it is assumed that there is sufficient local gas supply available for additional CCGT projects in the NI beyond 2025 that have a similar cost to NI and SI renewable options. In this case an HVDC charge could delay cheaper SI renewable options by many years and hence result in a higher present value cost.

A.7 Generation investment inefficiency with a MWh allocation

A.7.1 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.

A.7.2 The investment inefficiency analysis has been repeated with a $7/MWh net cost. The results are summarised in Table 45 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[138].

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

[138] Note that there are additional economic inefficiencies associated with the HAMI price structure relating to the incentives it provides to withhold capacity from the SI market and to discourage incremental SI peaking capacity. These are quantified in A.15.

Table 45 Generation Investment Inefficiency with a $7/MWh HVDC cost

Additional "baseload" investment cost $m NPV				
	Average	**Min**	**Max**	**Std dev**
1. Sustainable Path	$16	$3	$25	$6
2. SI Wind	$15	$9	$24	$5
3. Med Renewables	$14	$10	$18	$3
4. Coal	$19	$9	$40	$10
5. High Gas Discovery	$21	$11	$29	$5
Average/Min/Max/Std dev	**$17**	**$3**	**$40**	**$6**

A.7.3 The sensitivity analysis for a $7/MWh HVDC cost suggests an economic cost in a band of $3m to $40m (average $17±6m).

A.7.4 The reason why the economic cost is lower in this case is that the inefficiency relates mainly 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.

A.8 HVDC rental allocation sensitivity

A.8.1 The Authority has made Code amendments to allow for the introduction of Financial Transmission Rights (FTRs) between Benmore (BEN) and Otahuhu (OTA). 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.

A.8.2 When this is implemented SI generators paying for HVDC assets would no longer get HVDC rentals. As a default arrangement, SI generators paying for HVDC assets will receive a share of residual FTR revenue that related to the HVDC.

A.8.3 In theory the residual FTR revenue should be approximately equal to the expected future value of the BEN to OTA net rentals. However it is proposed that there be a 6 month lag in allocating revenues, and that some revenue may be retained in the FTR account to support revenue adequacy. This may affect the value to recipients. There will also be issues relating to the allocation of auction proceeds between HVDC and other assets used to support the BEN-OTA FTRs, as there will not be a market based contract value for the HVDC rental stream.

A.8.4 In addition the Authority is concerned that there could be competition issues if parties who participate in FTR auctions also receive a significant share of the proceeds. For this reason it is considering other options for allocating the residual FTR revenue. In some of the options SI generators who pay for HVDC assets would no longer receive the value of HVDC rentals.

A.8.5 Sensitivity analysis is used to deal with this uncertainty. The base case analysis assumes that SI generators continue to get the full value of HVDC rentals and hence the net HVDC cost is equal to approximately $35/kW/yr which equals the gross HVDC charge (approximately $40/kW/yr) minus the expected value of the HVDC rentals post pole 3 (approximately $4-6/kW/yr). The alternative sensitivity assumes that SI generators get no HVDC rentals and hence the HVDC cost is the full $40/kW/yr.

A.8.6 Table 46 shows the economic cost of HVDC charges (under counterfactual 2) in the event that SI generators receive no rentals, and hence face the full gross HVDC charges of $40/kW/yr.

Table 46 Generation Investment Inefficiency from HVDC charges without rentals.

Additional "baseload" investment cost $m NPV				
	With Rentals		Without Rentals	
	HAMI	MWh	HAMI	MWh
1. Sustainable Path	$22	$16	$26	$19
2. SI Wind	$23	$15	$31	$20
3. Med Renewables	$21	$14	$25	$18
4. Coal	$24	$19	$35	$22
5. High Gas Discovery	$31	$21	$39	$28
Average	**$24**	**$17**	**$31**	**$21**
Minimum	$10	$3	$11	$7
Maximum	$48	$40	$66	$41
Standard Deviation	$9	$6	$11	$6

Note: This is based on counterfactual 2 and assumes Meridian can develop 50% of generic SI projects

A.8.7 In this case the generation investment inefficiency is increased by around $7 to $4m to approximately $31±11m NPV for a HAMI allocation and $21±6m NPV under an MWh allocation.

A.9 Counterfactual Sensitivity

A.9.1 The table below shows the sensitivity of these results to the assumed counterfactual and the assumed percentage of the generic new SI projects that Meridian develops.

Table 47 Sensitivity of Investment Inefficiency estimates to choice of counterfactual

Additional "baseload" investment cost $m NPV					
Counterfactual	CF 1	**CF2**	CF2	CF3	CF3
Meridian % of generic		**50%**	100%	50%	100%
1. Sustainable path	$27	**$22**	$19	$18	$14
2. SI Wind	$31	**$23**	$20	$20	$15
3. Med renewables	$26	**$21**	$18	$18	$13
4. Coal	$32	**$24**	$22	$18	$15
5. High gas discovery	$40	**$31**	$27	$25	$20
Average	$31	**$24**	$21	$20	$15

Note: This is assumes the value of HVDC rentals is retained.

A.9.2 The base analysis assumes an expected case where Meridian bases its investment decisions on counterfactual 2 (i.e. a 50% risk that its investment may crowd out other SI investments during its life), and it develops 50% of the generic SI projects. The generation investment inefficiency could vary plus $7m or minus $9m if different assumptions were used.

A.10 Limitations of the analysis

A.10.1 The Biggar Report and a number of submitters question the significance of the results and point out the limitations of this simplified analysis.

A.10.2 With respect to the significance of the results, it is true the size of the generation investment inefficiency is low at around $24±9m NPV compared with the total new investment cost of $7-8 billion dollars over 30 years. However the analysis is focused on estimating the impact of a certain change in the cost of SI options (arising from HVDC cost allocation) on the timing of new investment, not the total cost of the investment plan itself. This impact is bounded below by zero and could be as high as $150m under certain assumptions. The range of the generation investment inefficiency ($24±9m) should be seen in the context of the maximum possible range of $0 to $150m, and should be compared with the cost of changing the TPM (which includes the implementation costs of the order of $1-2m NPV, the allocative impact of the change in cost recovery and the size of any consequential impact on future HVDC investment expansion decisions).

A.10.3 TPAG recognizes that there is a reasonable degree of uncertainty in the estimated generation investment impact of the HVDC cost allocation which depends, for example, on the assumed investment disincentive arising from the counterfactual and the actual costs of new projects. The nature of this uncertainty is not symmetric as it is bounded below by zero, but could possibly be as much as $150m NPV. The analysis attempts to account for the key factors which can influence the outcome so as to narrow the expected one standard deviation range to $24±9m. There will still remain a degree of uncertainty which no amount of analysis will be able to reduce, as it depends on future states of the world and costs which are inherently uncertain.

A.10.4 It is true that there are limitations with this simplified analysis for example:

- The analysis focuses only on the timing of new baseload and renewable options rather than the full mix of mid-merit, peaking and baseload. There will be tradeoffs between existing thermal generation (e.g. retirement, refurbishment or change in role) and new generation, thus the economic demand for base load investments could be greater or less than assumed.
- The analysis does not model the operation of the full system and hence relies on heuristics to account for factors such as peaking factors and marginal loss factors to enable thermal, geothermal, wind and hydro options to be ranked on a baseload equivalent basis.
- While extensive sensitivity analysis is used, the analysis is deterministic in the sense that in each scenario or sensitivity it is assumed that projects are developed in order of lowest cost.
- The approach is not suited to more complex scenarios, such as rising gas and carbon prices, gas discoveries, new technologies etc.
- There may be other factors influencing the commercial timing of new investment in each island other than cost (portfolio effects, option values etc), although this is often difficult to model as it involves very subjective estimates of the level and correlation of future risks.
- The approach does not directly model spot price formation so the impact on wholesale prices needs to be inferred by the cost of new entry of different types in different regions.

A.10.5 Some of these limitations can be addressed using more complex models, for example the Authority's GEM cost minimising model, a full market simulation model which includes participant bidding behaviour and hydro simulation or a stochastic optimisation model.

A.10.6 While these much more complex models can address some of these limitations, it is not clear that they would be able to reduce the inherent uncertainty significantly and they each have their own limitations as outlined below.

- The GEM model can model the full system to a degree, but it still involves significant simplifying assumptions and it is a central planning cost minimising model which does not necessarily reflect commercial decisions in the real market.
- Full market simulation models require a set of behavioural assumptions (such as bidding strategies and new investment rules) which can significantly affect the outcomes. In most of these models it is necessary to make the assumption that new investment occurs when expected net revenues spot prices rise sufficiently to cover the life time capital and operating costs. This is the same assumption used in the simplified analysis.
- Stochastic optimisation requires assumptions concerning the variations, correlation and evolution in the future uncertainties. These techniques are often relevant to decisions in regard to developing new options (e.g. decisions to incur the cost of land or resource costs to enable a generation option to be developed in the future when the market conditions are suitable). However they are unlikely to be a more significant factor, affecting the estimated impact of removing the HVDC cost allocation, than the other inherent uncertainties already accounted for in the simplified analysis.

A.11 Robustness to modelling heuristics

A.11.1 The simplified model used to assess the generation investment inefficiency includes a range of heuristics which might affect the results. These include:

- The factors used to account for wind intermittency –values of 90% to 92% are used based on historical values and estimated capacity contribution measures; however these could be as low as 85% or as high as 95%.
- The annual availability factors for new thermal – a value of 85% is used, but these could be 80% to 90%.
- The growth in the demand for baseload generation – a 30yr average growth rate of 1.6% p.a. is assumed, but this could vary by plus or minus 0.3% per annum. It could also be higher than assumed if existing base load thermal generation is retired or moves into a more mid-merit role as a result of increasing gas and or carbon prices.
- The expected marginal loss factors by region – these are based on historical data and regional factors from earlier GEM runs incorporating committed transmission investment, however these could vary by +/- 2%.

A.11.2 Submitters have also raised a number of other concerns regarding the assumptions used in the analysis:

- NZWEA suggested that the level of cheap geothermal might be understated and that the relative cost of wind may be overstated (or the expected capacity factors may be understated).
- TrustPower has stated that the analysis is too conservative and that it has SI options that could be economic were it not for HVDC charges.
- NZIER has concerns that capital costs for some options may not include all the avoidable transmission costs necessary to connect remote schemes to the grid.

A.11.3 A number of these concerns have been addressed by factoring these uncertainties into the scenarios used in the analysis. However TPAG also explored these effects through additional sensitivity analyses including the following:

- Increasing the expected capacity factor of wind by 2% and lowering the generic capital cost by 10%.
- Increasing the capital cost of additional geothermal beyond Ngatamariki by 10% and using a higher estimate of fixed operating costs.
- Doubling the connection costs for new projects in remote regions.
- Excluding the new potential schemes on the Clutha and lower Waitaki if resource consenting is too difficult or they prove too expensive.

A.11.4 The table below shows the sensitivity of the estimated generation investment inefficiency to reasonable variations in the heuristic factors used in the simplified modelling.

Table 48 Sensitivity of investment inefficiency to heuristic parameters

Additional "baseload" investment cost $m NPV					
Sensitivity	Average	Min	Max	Std Dev	Notes
Base	$23	$12	$35	$7	Wind PF=92%, HyRR PF=90%
Low Therm CF	$23	$12	$35	$7	Thermal CF = 80%
High Therm CF	$23	$12	$35	$7	Thermal CF = 90%
Low Demand	$20	$10	$30	$6	Demand -0.3% pa
High Demand	$23	$13	$38	$7	Demand + 0.3%pa
Low Wind PF	$20	$14	$40	$8	Wind PF = 85%
High Wind PF	$27	$13	$40	$9	Wind PF = 95%
Low MLF	$26	$16	$38	$6	MLF - 2%
High MLF	$20	$11	$29	$5	MLF +2%
High wind CF & low cost	$28	$12	$53	$11	2% higher CF and 10% lower cost
High geo costs	$27	$17	$43	$8	10% higher capital cost & high FOM
Higher connection cost	$20	$12	$26	$5	100% higher connection costs
Exclude Clutha & Waitaki	$20	$10	$34	$7	Exclude hydros on Clutha & Waitaki

Note: This is based on counterfactual 2 and assumes Meridian can develop 50% of generic SI projects and the value of HVDC rentals is retained. The base case used here assumes a $13/GJ gas price, $40/t carbon price and unrestricted geothermal and hydro.

A.11.5 This additional sensitivity analysis indicates that there could be a plus $5m or minus $3m NPV impact on the estimated average generation investment inefficiency. Higher demand, lower MLFs, higher wind peaking factors and lower wind costs would increase the estimated inefficiency. Lower demands, higher MLFs, higher connection costs, lower wind peaking factors and excluding Clutha and Waitaki hydro options would reduce the estimated inefficiency. The result is relatively insensitive to the assumed thermal availabilities, which indicates that most of inefficiency relates from the delay in SI renewables relative to NI renewables.

A.12 Impact of disorder in the development merit order

A.12.1 The analysis above is based on the assumption that projects are developed in order of LRMC. While there is significant scenario and sensitivity testing on factors that influence the natural merit order on new baseload and renewable options it is assumed that projects are developed in the chosen order (with or without the HVDC charge). In submissions, Fonterra and NZ Steel raised a concern that this assumption is unrealistic and in the real world there is likely to be a degree of disorder in the development arising from the evolution of external factors over time or other company specific considerations (retail or generation strategy, portfolio impacts etc).

A.12.2 TPAG recognises that some degree of disorder is possible in the real world and has examined the impact that this might have on the estimated mean generation investment inefficiency. This is approximated by adding an average $5/MWh (5%) or $10/MWh (10%) random adjustment to the LRMC estimate when determining the merit order ranking and then repeating the earlier analysis. This random adjustment is assumed to increase slowly over time.

A.12.3 This experiment showed that this increases the range and standard deviation in the estimated generation inefficiency, but does not significantly affect the estimated expected value by more than $1 to $2m NPV, well within the range of error of other factors discussed above.

A.13 Comparison with GEM modelling results

A.13.1 The Commission has already carried out experiments using the GEM model to estimate the economic cost of generation investment inefficiencies arising from the HVDC charge. The results given in Appendix 4 of the Transmission Pricing Review: Stage 2 Options, July 2010 showed $6-$36m NPV generation investment inefficiency. These results are broadly similar to the simplified analysis, but are not strictly comparable with the updated analysis as they were based on a lower HVDC cost ($30/kW/yr), assumed counterfactual 3 only, used lower discount rates to rank generation projects, imposed higher capacity margins than the standard and used outdated capital cost estimates and efficiencies for some plant types.

A.13.2 The more transparent simplified analysis used by TPAG was developed, in part, to address concerns raised by submitters to the Stage 2 review that the GEM model was a complex black box, did not necessarily reflect commercial investment decision-making and did not adequately account for uncertainty regarding the capital costs of individual projects. Some submitters to the TPAG discussion paper have raised concerns that the new analysis is too simplified. In response to these concerns, TPAG asked the Electricity Authority update the earlier GEM analysis. This is in progress but the results are not yet available.

A.13.3 TPAG does not expect this update of the GEM analysis to significantly affect the conclusions of the simplified analysis. It may help to determine if the assumed demand growth for base-load and renewable generation is reasonable (taking into account plant retirements, the changing role for existing thermal plant and new thermal plant as gas and carbon prices increase). It may also help to assess if the assumed marginal loss factors are reasonable. The updated analysis needs to ensure that GEM's relative ranking of run of river hydro, peaking hydro and wind is consistent with historical measures, with other models that can better account for hydro management and correlations in supply and with the views of market participants who will be making decisions on new projects. It also needs to account for the wide degree of uncertainty in the capital costs and performance of individual geothermal, wind and hydro projects.

A.14 Competitive detriment from Meridian having a advantage over other SI entrants

A.14.1 The estimates of generation investment inefficiency are based on Meridian having a relative advantage in developing new SI projects compared with its competitors. The estimates assume Meridian uses counterfactual 2 in its SI investment decision-making. This implies it has an effective $23/kW/yr HVDC opportunity cost compared with $35/kW/yr for new entrants. This means it has $9 to $12/kW/yr advantage relative to new entrants or its smaller incumbent competitors. This equates to a $3 to $4/MWh advantage for typical SI wind and hydro projects.

A.14.2 This assumption lowers the generation investment inefficiency (since Meridian's projects will not be delayed as much), but gives rise to potential competitive detriment. This arises from:

- Meridian undertaking more SI projects and hence ending up with a higher market share than otherwise; and
- Meridian facing less competitive pressure, with potential implications for contract prices in the SI and for productive and investment execution efficiency.

Impact on Meridian market share

A.14.3 The simplified model can be used to estimate the potential impact removing the HVDC charge on Meridian's market share in the SI.

A.14.4 Without the HVDC charge there will be full competition for new SI projects and Meridian's SI market share during 2020 to 2029 could fall from 69% to around 61% (59-63% depending on scenario).

A.14.5 However with the HVDC charge remaining and with Meridian having an advantage over its competitors such that it develops 50%-100% of the generic projects, Meridian's market share would only fall to 64-66% (3-5% higher than that likely without the HVDC charge)[139].

A.14.6 This impact on market share can be compared with the 5-6% reduction in SI market share that resulted from the forced sale of the Tekapo power stations to Genesis, which was estimated to cost $4 to $30m[140].

Impact on wholesale prices

A.14.7 Removal of HVDC charges on new SI generation will reduce SI new entrant costs by around $8-11/MWh for typical wind or hydro projects.

A.14.8 While this may not have an immediate impact on spot prices[141] it is likely to flow through into SI and New Zealand forward contract prices and into future spot prices as the level and timing of new investment (and incumbents behaviour) adjusts to a new equilibrium.

A.14.9 With demand growth (or plant retirement) spot prices can be expected to increase over time. When they are high enough, competitive new entrants will invest at such a level that, following entry, spot and contract prices are sufficient to cover their expected operating and fuel costs and provide a return on the capital invested. The actual outcomes in the spot market following entry may vary as a result of demand, hydrology variations etc. But new entrants can contract to reduce their exposure to these fluctuations. If there is too much entry, or if demand growth falls, then expected spot and contract prices will fall again and new entry will be deferred until extra demand growth (or plant retirements) causes the expected spot and contract prices to rise again.

A.14.10 Where there is weak competition in the spot market, large incumbents may have (from time to time) the capability to withhold capacity or price up their capacity to increase spot prices in the short run. While this strategy may be profitable in the short run (depending on the incumbent's contract level), it can quickly become counterproductive if prices are held up so high that this triggers premature entry by competitors, as this leads to incumbents simply losing market share and having to withhold greater and greater capacity from the spot market to maintain higher prices. Incumbents cannot easily prevent new entry and large customers have second order incentives to contract with new entrants or small competitors to enter earlier or at a larger scale in this situation. A more profitable strategy for a large incumbent is to withhold or price up so that

[139] Note that if Meridian were to develop all of the possible new SI projects (including projects such as Arnold, Mahinerangi stage 2, Wairau, and hydro on the Clutha) as suggested by NZIER, then its SI market share (averaged over 2020-29) could increase to around 73%, 12% higher than the 61% that might be expected if the HVDC charge was removed.

[140] See "Improving electricity market performance: Summary note on recommendations taking account of submissions" MED Oct 2009 page 73.

[141] Since, as several submitters have observed, the HVDC HAMI charge is not a direct component of the short run marginal cost of the price setting generators.

spot and contract prices just approach the cost of new entrants, so as not to trigger new entry until it is required to meet demand growth[142].

A.14.11 In workably competitive oligopoly markets this competitive dynamic often reflects in forward contract prices (i.e. contract prices beyond the influences of short term random fluctuation in inflows or supply and demand) bumping up to the cost of new entrants. More competitive markets tend to show periods of lower contract prices whenever there is a relative surplus of supply over demand.

A.14.12 This effect cannot be readily observed in spot prices as, in New Zealand, these are dominated by inflows and the fluctuations in hydro storage as illustrated in Figure 1. To see the linkage it is necessary to look at comparison between year-ahead forward contract prices and the lowest cost baseload new entrant LRMC (gas fired CCGT until recently, then geothermal once gas and carbon prices rise) as shown in Figure 2. This shows a broad correlation between contract price and LRMC. There is some evidence that contract prices have fallen somewhat below LRMC in the 2008-2011 period as a result of lower than expected demand growth resulting from the economic recession and reduced demand at Tiwai. This is indicative of a workably competitive oligopoly market.

A.14.13 The long run competitive dynamic described above means that a reduction in the cost of new entry is expected to flow into wholesale contract and future spot prices. If the level of competition is weaker the quicker the flow on effect is likely to be. In this case it is the independent new entry cost to others that is likely to flow through to prices, rather than the cost to the incumbent. This means that the price impact is more likely to reflect the full $8-11/MWh level of the HVDC charge rather than the lower effective rate for the large incumbents.

A.14.14 It is only SI new entry prices that are influenced by the HVDC charge and hence it is necessary to look at the balance of supply and demand and competition between each island. There will be many situations where there is an effective national competitive market. However when constraints on the HVDC bind, the markets can separate and prices can diverge. Pole 3 reduces the risk of constraints significantly (particularly from South to North), however there still remains a risk of North to South constraints[143] in dry years. This risk can be mitigated through conservative hydro storage management, but this increases the probability and duration of NI to SI HVDC transfer during drier than normal years and the risks of significant (North to South) inter island price separation. This can cause SI contract prices to continue to rise above NI prices until they are sufficient to justify a minimum level of SI generation investment[144] to offset the SI demand growth.

A.14.15 This issue is not captured in the simplified LRMC modelling as this does not account for hydrological fluctuations and the increasing risks of dry year price separation if there is no new SI generation investment to match demand growth. In submissions TrustPower suggested that this may lead to existing HVDC charges already being factored into SI forward contract prices, and

[142] Note that because new entrants have sunk costs, it is possible that contract prices may be held at a margin above new entrant costs, however this does not mean that a certain reduction in new entrant LRMCs will not be reflected through to a reduction in forward contract prices. Similarly in a market with rising LRMCs it is possible that entrants may enter slightly earlier than indicated by its simple LRMC (since it expects higher revenue later), however this does not mean that a reduction in LRMC will not flow through to contract and future spot prices.

[143] Either across the HVDC, or more likely, through the lower North Island HVAC system.

[144] Either by bringing forward some wind or by building thermal hydro-firming plant.

hence a reduction in the SI new entrant cost may flow through into SI prices much earlier than the earlier analysis suggested.

A.14.16 TPAG has explored this issue and notes that there is some evidence for this effect:

- ASX forward contracts for Benmore in 2013-14[145] are higher than those at Otahuhu.
- Market modelling carried out by Energy Link in March 2011[146] shows the same feature. This work simulated the operation of the market over a full set of hydrology and accounted for bidding rules used to manage hydro storage and constraints in the AC and HVDC system in wet and dry years. This modelling showed that, absent a minimum level of SI new generation investment, the dry year risks rise and as a result SI expected spot prices exceed Otahuhu levels from 2014 until 2024.

A.14.17 The minimum level of SI generation necessary to avoid significant price separation is likely to be relatively small. However it is unlikely to emerge in a commercial market unless SI wholesale contract prices are at a level to justify it. This means that a lowering of SI new entry costs may flow relatively quickly into SI prices, even in the period when SI new projects are more costly than NI options.

A.14.18 Once SI generation options become more competitive with NI options (i.e. once most of the relatively cheap geothermal is fully developed) it is likely there will be sufficient SI investment to substantially reduce the risk of significant price separation in dry years, and contract prices in both islands are likely to move together (separated by marginal loss factors only) and reflect the cheapest new entry cost in the New Zealand market overall.

A.14.19 The TPAG analysis in the Discussion Paper considered only this long term impact on national wholesale prices, and conservatively ignored the potential impact in the SI. This means that it may have underestimated the value gain to SI customers (and the value loss to SI generators). It is possible to approximate the potential value from this by calculating SI and NI specific impacts.

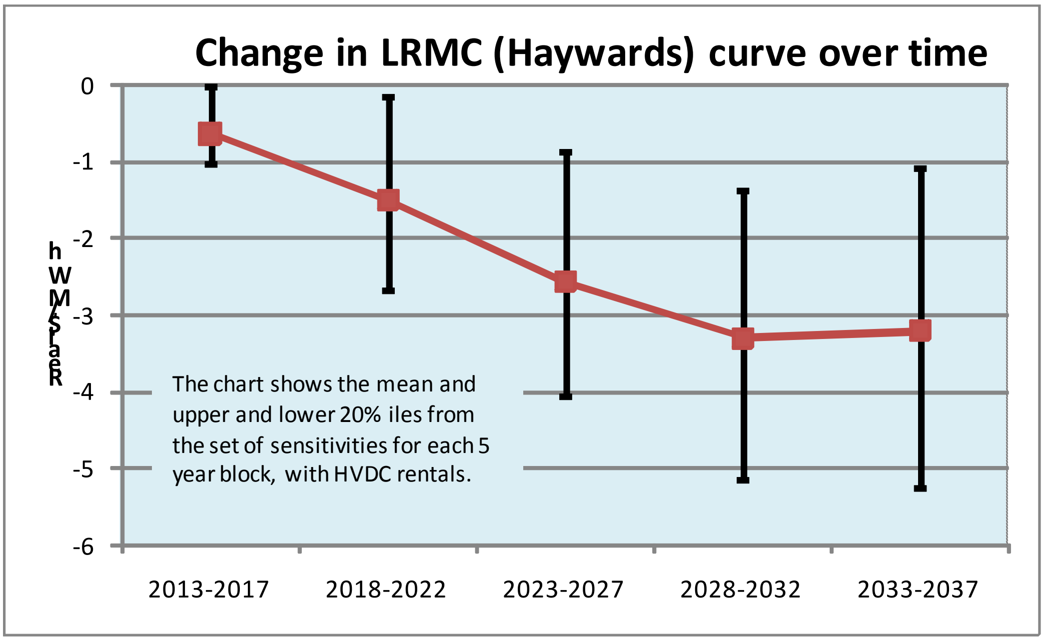
Impact on NI wholesale prices

A.14.20 The NI wholesale price impact can be approximated using the same merit-order approach used to estimate the generation investment inefficiency. Figure 16 shows the mean and percentiles of the five year average LRMC reduction (referenced to Haywards) resulting from removal of HVDC charges on new SI generation. These estimates are derived by recording the LRMC impact from 110 sensitivities (including the 5 scenarios and 20 randomly selected sets of individual project capital costs).

[145] Note that these longer-term contracts have limited liquidity and so their reliability is not as great as shorter term contracts.

[146] See “Losses and Constraints Excess Projections”, Prepared by Energy Link for the Electricity Authority, March 2011. This work was carried out for the Locational Price. See Figures 11, 24 and 27.

Figure 16 Impact of removal of HVDC charges on the NI LRMC curve



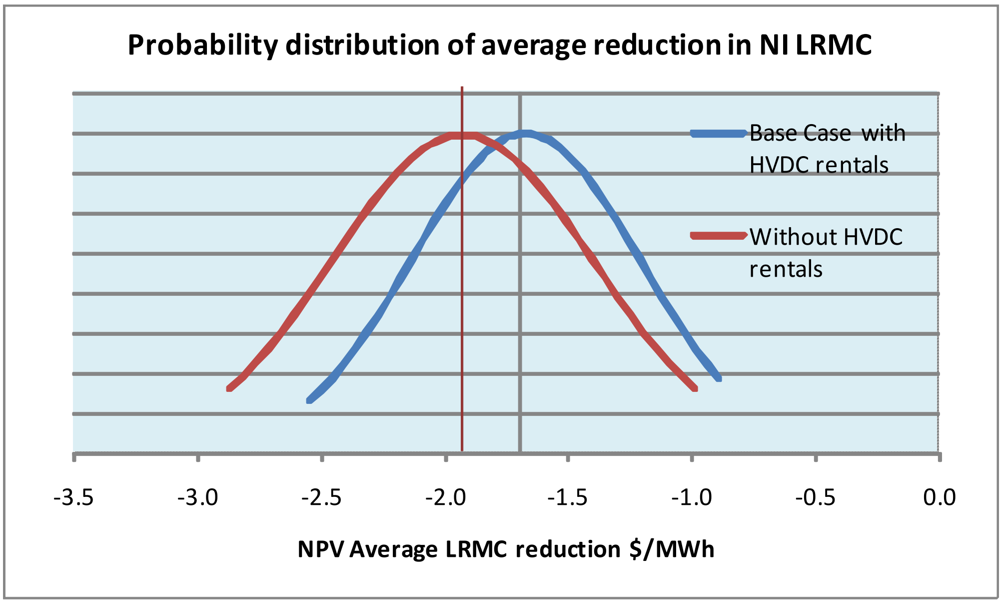
A.14.21 As can be seen, the impact on the New Zealand LRMC is relatively low initially but increases over time. This reflects the fact that the LRMC is mainly set by low cost NI geothermal options over the next 5 years or so, but then can be set by either NI or SI generation options depending on their cost.

A.14.22 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 less certain over time.

A.14.23 The present value average impact on the LRMC is illustrated in Figure 17[147]. This has a mean of approximately -$1.7/MWh and a standard deviation of around $0.4/MWh.

[147] The present value average impact is derived by taking the present value of customer costs 25 years at a 9% real pre tax discount rate and dividing by the present value of customer load.

Figure 17 The probability distribution of the PV impact on LRMC



A.14.24 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.

Impact on SI wholesale prices

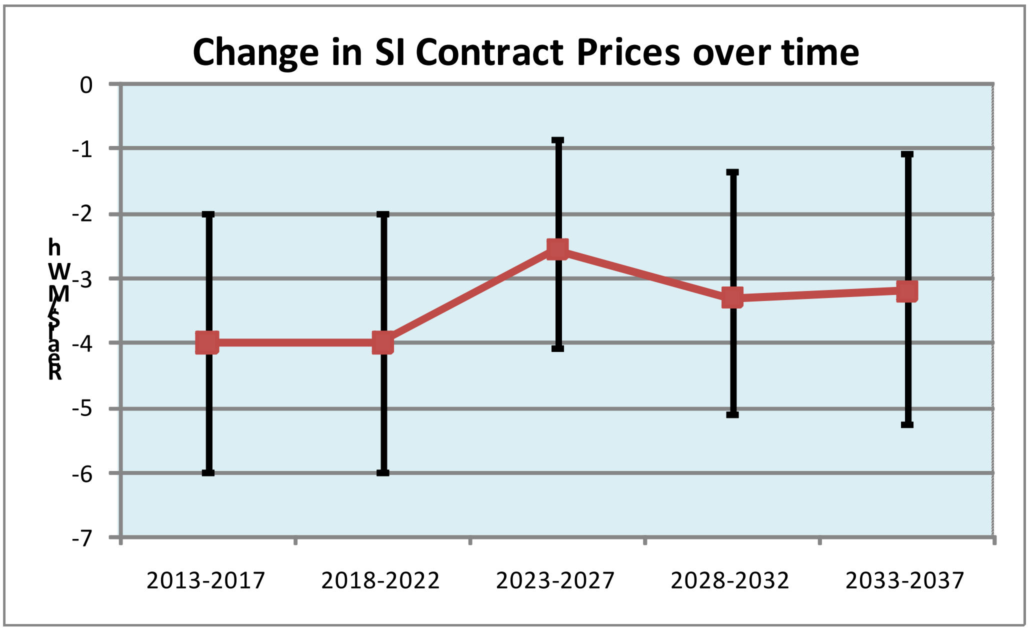
A.14.25 There is some evidence that a reduction in SI new entry costs may have an early impact on SI wholesale prices if, with SI demand growth, some minimum level of SI new investment is required during the period 2014 to 2022 to reduce the risk of north to south inter-island transmission constraints binding in dry years. If this is the case then a reduction in SI new generation costs by $8-10/MWh is likely to have a significant and earlier impact on SI wholesale contract prices.

A.14.26 The evidence for this is not conclusive, and even if this is an issue it is difficult to know what the impact on SI prices might be.

A.14.27 In light of this uncertainty, TPAG has explored the implications of a scenario with a possible $2 to $6/MWh impact on average SI prices during the period to 2023. Beyond this period the reductions in SI wholesale prices should follow the reduction expected in the NI once there is more balanced pattern of NI and SI new generation development which ensures that the risks of significant north to south constraints occurring in dry years is reduced.

A.14.28 Figure 18 shows the likely impact on SI prices, including an assumption that SI prices are lowered by $2 to $6/MWh during 2015 to 2023.

Figure 18 Impact of removal of HVDC charges on SI contract prices



A.14.29 The present value average has a mean of -$3.5/MWh and a standard deviation of around $2/MWh.

Conclusions on competitive impacts.

A.14.30 The analysis indicates that removal of the HVDC cost allocation to new entrant SI generators is likely to lead to the following competitive benefits over the next 30 years:

- SI new generation options would compete on an equal basis with NI options, rather than suffering an $8-10/MWh disadvantage;
- Meridian would no longer get a $3-4/MWh advantage over its competitors in the SI;
- Meridian's market share in the SI is likely to fall around 3-5% more than that expected in the status quo;
- there is some, inconclusive, evidence that SI wholesale contract prices may fall by $2-6/MWh in the medium term as the LRMC of SI options needed to reduce the price separation arising from management of dry year risks is lowered by $8-10/MWh. There could be a greater reduction if there is weak competition in the SI as a result of Meridian's dominance of the market; and
- both NI and SI contract prices may fall by around $3/MWh beyond 2020 once the cheaper NI geothermal options are developed and NI and SI options are more comparable.

A.14.31 It is difficult to estimate the productive impacts of this, however there are some benchmarks.

- Anticipated economic gain from increased competition resulting from the transfer of Tekapo (which reduced Meridian's SI capacity share by 5-6%) must have exceeded the estimated cost of $4-30m. A further 3-5% reduction in Meridian's SI market share might deliver some portion of this implied benefit[148].

- It is difficult to estimate the impact of increased competition from new entrants on a large incumbent's productive and investment execution efficiency. However it is very likely that the combination of increased competition from other incumbents and new entrants in the SI and the likely lowering of SI wholesale prices will put pressure on Meridian to cut costs and improve its performance. Even a very small improvement in performance can give rise to significant productivity gains. For example a 2% improvement in Meridian's investment execution efficiency for 220MW in 2020 and a $0.04/MWh (0.2%) reduction in operating costs[149] would result in a $10m NPV productive efficiency gain.

A.14.32 Given the two considerations above, TPAG considers it is realistic to estimate the productive and investment execution efficiency gain from removing the competitive advantage to Meridian is to be $10m ± 5m NPV.

Allocative efficiency gain from price reductions

A.14.33 The allocative gains from net price reductions (or increases) to customers can be estimated by separately calculating the additional consumer surplus from the addition demand arising from a reduction in delivered electricity prices assuming a -0.26 price elasticity.

A.14.34 Table 49 shows the results for full postage stamping, each of the postage stamp transitions and from the 'incentive free' option.

[148] Note that although the package of reforms was aimed at increasing retail competition, this could have been achieved through the virtual asset swaps and so the additional cost of the physical asset transfer must have been justified on the basis of benefits from increased wholesale competition. Not all of this implied benefit can be attributed a reduction in Meridian's market share in this case. This is because the transfer of Tekapo to Genesis also involved the transfer of control of a significant portion of SI hydro storage to a competitor as well as a reduction in market share.

[149] Note that the cost benefit analysis of the proposal to introduce an FTR market to manage locational risk included an assessment of the productivity gains arising from increased competition between NI and SI generators. In this analysis the assessed price impact was between $0.36 and $0.71/MWh and the assessed productivity impact (from generators operating more efficiently to retain margins) was 50% of this level ($0.18 to $0.36/MWh). See "Managing locational price risk: Proposed amendments to Code", April 2011, pages 86 and 87. The illustrative productivity gain used in this calculation is only 10 to 20% of the assessed gain from increased competition arising from the FTR contract market.

Table 49 Allocative efficiency gain from net delivered price reductions

HVDC Option	High 25 yr NPV $m	Expected 25 yr NPV $m	Low 25 yr NPV $m	Expected 25 yr NPV $m
Early SI wholesale price Reduction $/MWh	$6/MWh	$4/MWh	$2/MWh	None
Full postage stamp	$1.4	$0.2	-$0.1	-$0.3
Transition $45/kW/yr & 5 years	$2.5	$0.4	$0.5	$0.4
Transition $30/kW/yr & 10 years	$2.7	$1.2	$0.5	$0.5
'Incentive free' - 25 years	$5.6	$3.4	$2.2	$2.0

Notes: This analysis assumes that the market exhibits the characteristic of a workably competitive market with rivalry between incumbents and open access to new entrants. In this market wholesale prices are limited by the threat of new entry, and hence reductions in new entry costs arising from removal of the HVDC charge will flow through to customers in the medium term.

A.14.35 The estimated NPV allocative gain (loss) accounts for the net impact of wholesale price reductions and transmission price increases in each island over a 25 year period. The transmission price increase varies according to the HVDC option being considered.

A.14.36 If there is an expected $4/MWh medium term reduction in SI wholesale prices then the alternative options would deliver between $0.2 to $3.4m NPV allocative gains, otherwise the allocative gains could be between -$0.3m to $2.0m NPV.

A.14.37 In each case the allocative gain from the 'incentive free' option is the greatest as this has the same expected reduction in wholesale prices, without any offsetting increase in transmission charges to customers. In all cases the allocative efficiency gains or losses are low compared with estimated generation investment inefficiency.

A.15 Potential peaking generation investment inefficiency

A.15.1 The analysis above considered the potential base load and renewable generation investment inefficiency arising from the HVDC cost allocation. There is also the potential for peaking generation investment inefficiency as a result of the HAMI cost allocation methodology.

A.15.2 This potential inefficiency can arise if the HAMI pricing structure results in the delay of cheaper SI peaking generation investment and the bringing forward of more expensive NI peaking generation.

A.15.3 This potential peaking investment inefficiency was estimated to be $0-25m in earlier work carried out by the Electricity Commission (Appendix 4 to the Stage 2 Consultation paper) and is updated here.

A.15.4 For SI peaking capacity to have value in the NI it is necessary that there is sufficient firm capacity on the HVDC to transfer the excess SI peaking capacity (above SI peak demand) to the NI. Figure 19 below is derived from the 2011 Annual Security Assessment (ASA) published by the System

Operator in Jan 2011. This shows the measures of SI peak demand[150] and SI capacity supply as used in capacity margin assessments. Also shown is the maximum firm SI capacity that can be transferred across the HVDC. This accounts for losses and NI instantaneous reserve requirements[151]. Three components of the SI peak generation capacity are shown. The base level is that used in the ASA which includes the existing SI generation plant as it is currently offered to the market. It includes only 680MW of the full 752MW from the Clutha scheme as Contact is restricting the capacity. The additional MW peaking capacity available from the Clutha and Manapouri schemes[152] and other new SI renewable generation that might be built is also shown. The particular profile of new SI generation capacity shown in the figure is illustrative only and is based on the new capacity without an HVDC charge from sensitivity 4 in Table 44. The chart also includes an additional 200MW peak capacity that might be available at relatively low cost from upgrades to existing SI hydro plant. This potential was identified in the earlier work carried out by the Electricity Commission.

A.15.5 The figure shows that until pole 3 is commissioned there is excess SI peak generation capacity. This means the full value of SI peaking capacity cannot be realised and may explain why SI generators are currently withholding peak capacity from the market to avoid HAMI HVDC charges. Once pole 3 is commissioned the current excess of SI peaking capacity can be transferred over the HVDC and will have significantly more value in the North Island. It is expected that the NI value will exceed the HAMI charge and hence it should be economic to offer most or all of the existing SI peaking capacity into the market even if HAMI HVDC charges remain.

A.15.6 In submissions, MEUG's report by NZIER suggested that this would imply that the total dispatch inefficiency arising from the HAMI charge will be zero beyond 2013. However the arguments outlined above only applies to the withholding of fully controllable capacity (which can always contribute to avoid capacity shortfalls in the North Island). However the HAMI charge can continue to be a potential issue for uncontrolled capacity (eg run of river, within-chain capacity). This will earn only a portion of the NI capacity value and hence the HAMI charge may continue to discourage some withholding in these situations. Withholding of capacity in these situations can result in increased hydro spill. The amount of capacity of this type is relatively small (since most of this capacity is embedded and hence is not subject to the HVDC charge). However there could be 50 -100MW affected. A 1-2% loss from additional spill could cause $1-5m NPV inefficiency. The inefficiency is likely to be towards the lower end of this range.

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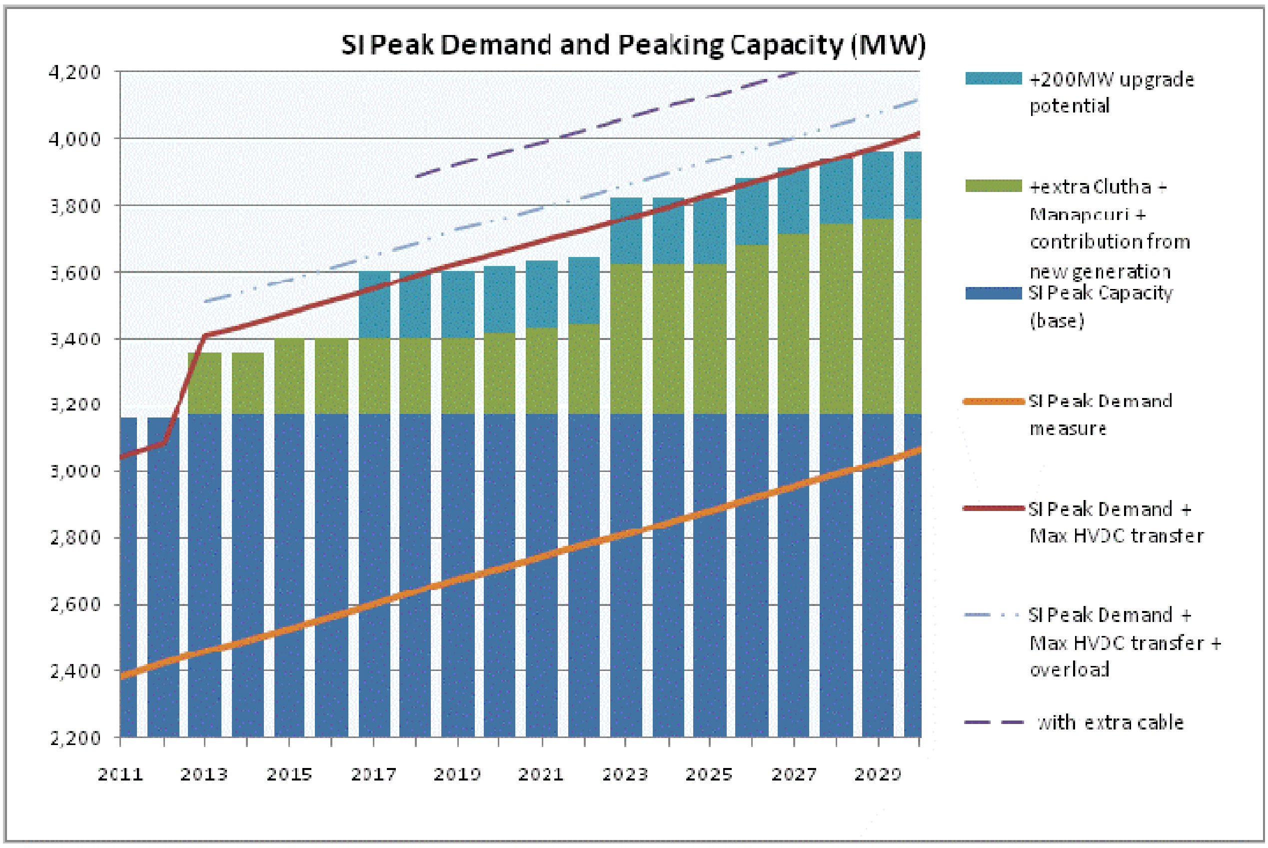
[150] The capacity margins in the ASA use a measure of peak demand which is the average of the top 200 trading periods. This is adjusted by an empirical allowance of 130MW for SI reserves and NI/SI demand diversity etc. The contribution to peak capacity uses derating factors which accounts for plant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

[151] Prior to pole 3 the maximum transfer capability into the NI is around 660MW. This is the maximum that can be transferred without increasing the contingent event risk associated with the largest generation in the North Island (around 400MW). Once pole 3 is fully commissioned to 1200MW this limit is increased to 900MW, which is achieved by operating the 500MW pole at 400MW and the 700MW pole at 500MW. In this configuration the loss of the larger 500MW pole is partly covered by the other pole increasing from 400MW to the maximum 500MW and so the net contingent event risk is only 400MW (ie 500MW-100MW self cover). It is possible that some additional short term overload capacity may be available as well, but this is not certain. There will be other times when additional SI peak capacity can be sent north, but this relies on there being NI instantaneous reserves available at a reasonable price. An addition 200MW of firm capacity could be made available by installing an additional submarine cable and filters, but this is not committed and would involve a capital cost of around $125m(see footnote 153) . The potential impact of this is shown in the figure.

[152] Manapouri received revised resource consents in July 2010 to enable it to operate up to its installed capacity of 840MW, subject to possible operational and transmission constraints.

A.15.7 There appears to be adequate HVDC transfer capacity (at least for the next 10yrs) to accommodate the likely SI generation build and an extra 200MW of existing capacity upgrades, if these were available at a lower cost than NI peaking capacity. Additional firm HVDC capacity might be available if there is short run overload capacity on pole 2 and an extra 200MW could also be available if an additional submarine cable was built but this may involve a national cost of up to $60/kW/yr[153].

Figure 19 Expected peak supply and demand in the SI



A.15.8 There is a potential peak generation investment inefficiency arising from the HAMI charge if this results in cheaper SI peaking capacity (from existing plant upgrades or reconfiguration of new SI generation[154]) being delayed, and as a result more expensive NI peaking capacity is required to meet New Zealand capacity margins. For this inefficiency to arise the SI peaking enhancements would need to be commercially justified without a HAMI charge, and not justified with the HAMI charge. As discussed earlier, the effective HVDC charge will vary by company depending on its current share of HVDC charges (e.g. 69% for Meridian) and the investment counterfactual. In this case, there is limited spare peaking capability available (without investment in a new undersea cable) and hence there is a higher risk that investment in additional peaking capacity by one company may crowd out investment in peaking capacity by another company. This implies that

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

[154] For most new SI generation options it is possible to adjust the balance between energy and peaking capacity within some bounds. The HAMI charge structure tends to discourage adding additional capacity.

counterfactual 2 is likely to be used in investment decisions. With this assumption, Meridian's effective charge is around $23/kW/yr, Contact's is around $32/kW/yr and Genesis or TrustPower's is around $34/kW/yr.

A.15.9 This means that the SI peak upgrade options need to be between $0 and $23-$34/kW/yr[155] cheaper than the SI equivalent cost of NI peaking options[156] that could be deferred. If a SI upgrade option was greater than $23-34/kW/yr cheaper than the NI peaking options then the SI option would be commercially justified with or without the HAMI charge and so there would be no investment inefficiency.

A.15.10 The potential inefficiency depends on the quantity of upgrade capacity available for each company in the SI, the number of years that NI peaking capacity is deferred without having to incur the cost of an additional cable, and where in the $0 to $23-$34/kW/yr range the cost difference falls. The figure above indicates that NI capacity could be deferred 15 years; however this depends on the scenarios for new SI generation build without a HAMI charge and on SI demand growth. The extent of deferral could range from 5 to over 15 years.

A.15.11 Table 50 shows the estimated peaking generation inefficiency for an assumed 200MW upgrade capacity (split equally between Meridian, Contact and TrustPower or Genesis) for a range years of deferral and cost differences. The average effective HVDC charge for these companies is approximately $30/kW/yr.

Table 50 Potential peaking investment inefficiency from the HAMI cost allocation

MW SI Upgrade	200MW		
Cost Difference $/kW/yr (real)	$0/kW/yr	$15/kW/yr	$30/kW/yr
Years of Delay	2011 NPV Inefficiency $m[157]		
5 yrs	$0	$8	$15
10 yrs	$0	$13	$25
15 yrs	$0	$16	$31

A.15.12 This analysis indicates that there could be up to $31m peaking investment inefficiency arising from the HAMI HVDC cost recovery mechanism, if there is 200MW of SI peaking upgrade capacity available from existing hydro generation in the SI which is up to $23-34/kW/yr lower cost than NI peak generation options. This maximum peaking investment inefficiency would be around 15% higher ($36m) if the SI generators don't get the value of HVDC rentals.

[155] Note that this analysis assumes SI generators would continue to get the value of HVDC rentals and counterfactual 2 applies.

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

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

A.15.13 While it is plausible that there could be up to 200MW of additional peak upgrade capacity (for example there is scope to add additional turbines to the Clyde station and there could be additional mid-life refurbishment at some of Meridian and TrustPower's schemes over the next 10-20 years), it is not known if the effective cost of increasing peaking capacity would be in the required range if and when these options become available.

A.15.14 The analysis shows there is a clear risk that the HAMI cost allocation methodology might result in significant investment inefficiency, but it is not possible to be certain of this. For this reason the expected peaking generation investment inefficiency is assumed to be at the low end of the possible range. An indicative central value of $8±8m NPV is used in the cost benefit.

Appendix B Possible transition options

B.1.1 The appendix considers options for a transition to postage stamping the HVDC costs to off-take.

B.1.2 A transitional approach which retains the historical allocation of HVDC costs to grid-connected SI generators, and moves to postage stamping over a period of time may have merit if there is a proposal to move from the current HVDC cost allocation to SI generators to a postage stamp cost allocation to offtake. This would be consistent with good regulatory practice which seeks to promote consistency and stability in pricing. It would also remove the generation investment inefficiencies associated with the status quo without creating significant value transfers.

B.1.3 The transition could be implemented by requiring existing grid-connected SI generating stations to continue to pay for a portion of the HVDC costs over a transition period, and to have the remaining costs recovered via postage stamp charges to customers. The portion recovered from SI generators would be phased out over a transitional period, and the allocation between existing SI generators would be fixed in advance (and allocated to specific generating stations) 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.

B.1.4 The key transition parameters are:

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

B.1.5 The initial charge to existing SI generators could be:

- \$23/kW = the expected HVDC charge without pole 3[158] (50% of the total HVDC charge in 2013), or
- \$30/kW = the total expected HVDC charge in 2013 minus the incremental capital recovery cost for pole 3 assets = (65% of the total HVDC charge),or
- \$45/kW = close to the total expected HVDC charge in 2013

B.1.6 The length of the transition could be; short (5 years), medium (10yrs) or long (15 yrs).

B.1.7 The higher initial charge would be preferred to minimise step changes in prices and potential allocative loss, and the length of the transition could be set to minimise the value impact and to make an 'incentive free' fixed allocation to existing SI generators workable.

B.1.8 As discussed in Appendix A, the potential competition issues in the proposed FTR auctions would be avoided if existing SI generators no longer receive their share of residual HVDC rentals. This could be implemented by allocating all the residual HVDC rentals to customers from 2013 and accounting for the value impact of this when setting the initial portion and length of the transition period. The expected value of the HVDC rentals from 2013 is uncertain, but is likely to be in the range of \$4-6/kW/yr[159].

B.1.9 Table 51 shows the short run price impact and potential present value average price impact on end-use customers under the range of possible transition settings.

[158] Note that this is based on an extrapolation of the trend in HVDC charges up to 2009.

[159] See Appendix C.13

Table 51 Impact on end-use customers under alternative transition options

Transition Parameters			Impact on Present Value Average Price		
Initial charge to existing SI Gens	Transition length	Initial price increase to customers	Transmission Price increase net of rentals.	Mean net price increase	
				With early SI reductions	Without early SI reductions
$/kW/yr	Years	$/MWh	$/MWh	$/MWh	$/MWh
$0	0	$3.4	$2.4	-$0.2	$0.5
$23	5	$1.7	$1.9	-$0.5	$0.1
$23	10	$1.7	$1.7	-$0.8	-$0.1
$23	15	$1.7	$1.5	-$0.9	-$0.3
$30	5	$1.2	$1.8	-$0.6	$0.0
$30	10	$1.2	$1.5	-$0.9	-$0.3
$30	15	$1.2	$1.2	-$1.2	-$0.5
$45	5	$0.1	$1.5	-$0.9	-$0.3
$45	10	$0.1	$1.0	-$1.3	-$0.7
$45	15	$0.1	$0.6	-$1.7	-$1.0

Notes: Assumes $0.35/MWh value of HVDC rentals received.
The mean net price increase is given with early SI price reductions and without. The analysis of potential early SI price reductions is set out in paragraphs following A.14.25.

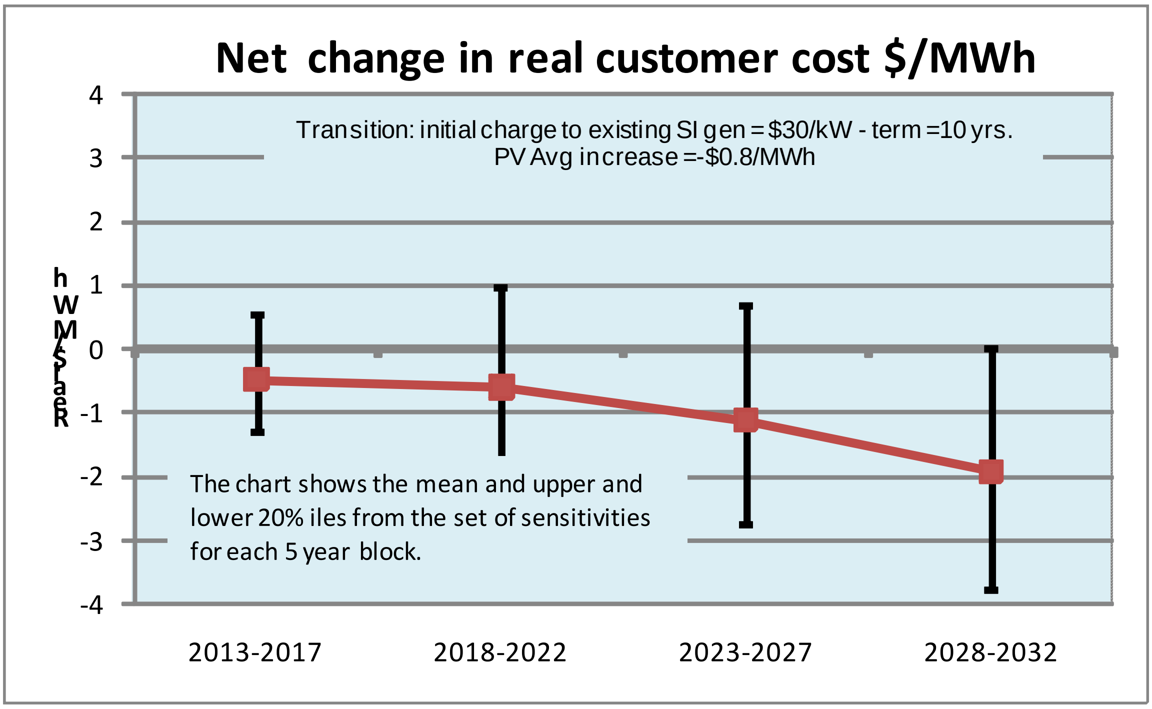
B.1.10 The table shows that either a $23/kW charge with a 15 year transition, a $30/kW charge with a 10 year transition or a $45/kW charge over a 5 year transition would leave end-use customers[160] no worse off than the status quo.

B.1.11 Of these, the shortest transition might be preferred as this makes a fixed ('incentive free') allocation of HVDC charges between existing SI generators more workable, and it also reduces the initial price impact to zero. A $30/kW initial charge with a 10 year transition would also be a reasonable option as it would only have a $1/MWh initial price impact and a smoother transition as it better matches the profile of the expected reduction in wholesale prices.

B.1.12 It is recognised that the higher transmission cost to customers is more certain whereas the potential offsetting wholesale price reduction is delayed and more uncertain. Figure 20 below illustrates this issue by showing the 20 and 80 percentile range for the potential impact on end-use customers under the $30/kW option with a 10 year transition.

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

Figure 20 The potential net impact on customers of a $30/kW 10 year transition



Notes: Assumes an intermediate early reduction in SI wholesale contract prices..

B.1.13 This chart shows there is high confidence that the net impact on average delivered customer prices would be less than around $1/MWh in the period to 2022, and there is a possibility for a $3-4/MWh reduction beyond 2023.

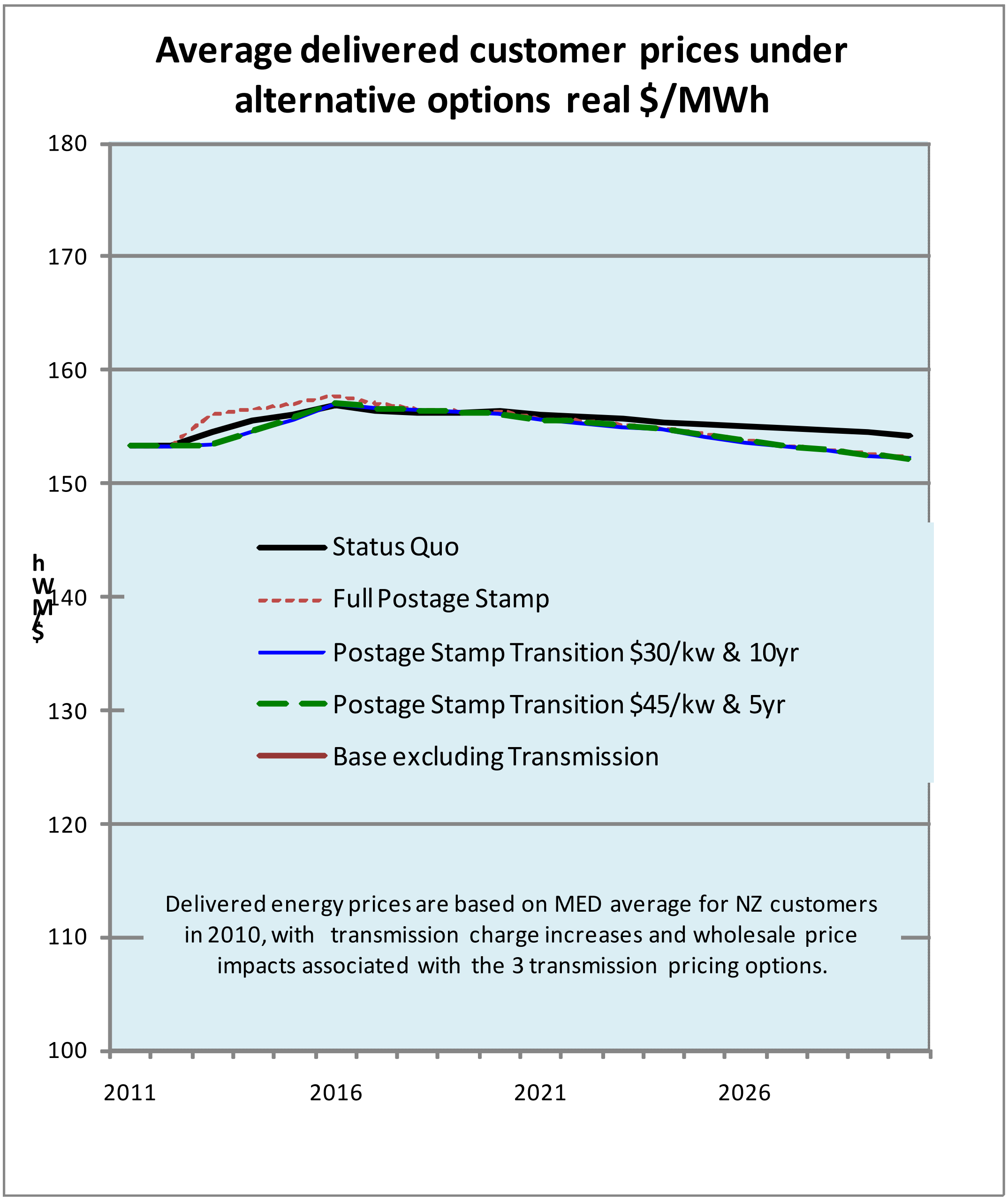
B.1.14 These potential price impacts are small relative to overall charges. For example $1/MWh is 0.6% of the New Zealand average delivered electricity price to customers in 2010[161], 0.4% of residential prices and 0.9% of industrial prices. Figure 21 below illustrates the expected impact of these HVDC options on the average delivered electricity prices in New Zealand. This chart includes the expected impact of new AC investments on transmission charges to loads and the expected impact of the HVDC postage stamp transition option[162].

B.1.15 If the uncertainty regarding future wholesale price falls was considered to be a significant issue then it would be possible to choose a longer transition (e.g. $30/kW and 15yrs, or $45/kW and 10yrs) which provided a net value gain to customers to compensate for the extra uncertainty.

161 Source: MED Data file.

162 Note that the chart uses 2010 average delivered energy prices as a reference and accounts for the impact on expected transmission charges and on wholesale prices of the HVDC options. The chart does not include any estimate of the future level of wholesale prices and distribution charges as this is simply set at the 2009 level.

Figure 21 Total delivered end-use prices under status quo, full postage stamp and postage stamp transition



Notes: Assumes an intermediate early reduction in SI wholesale contract prices.

Majority view on the appropriate postage stamp transition option.

B.1.16 The majority of TPAG members agreed any transition option must:

- avoid step changes in prices to end consumers with the costs recovered from existing grid-connected SI generators during the transition period based on the costs of existing HVDC assets as a starting point. This is to be achieved through a declining ‘incentive free’ charge to existing grid-connected SI generating stations beginning at $30/kW and

- incorporate a transition period to provide confidence that the efficiency benefits will flow into the wholesale market, without making the design of an 'incentive-free' transitional charge to existing SI generators unworkable. This is achieved by the selection of a 10 year transition period.

Appendix C 'Incentive free' allocation to SI generators

C.1 Introduction

C.1.1 Several submissions in response to the Discussion Paper suggested that there had been insufficient analysis of the option that involved a possible 'incentive free' allocation to SI generators and that the paper did not provide adequate reasons for concluding that such an option was unworkable.

C.1.2 The TPAG Discussion Paper indicated that: "*It is unlikely that this option would be implemented in a way that is workable long-term and did not lead to immediate disputes unless used as a transition arrangement*", was "*likely to be disputed immediately as an arbitrary allocation of costs to a group of participants*", and that "*it is considered by all to be unworkable and not durable other than as part of a transitional arrangement*".

C.1.3 In part this view was based on submissions to the Stage 2 Consultation Paper which showed little support for the development of an 'incentive free' allocation to SI generators, and several suggestions that it was impractical, unlikely to be sustainable, and amounted to an arbitrary exercise of regulator power.

C.1.4 However, several submissions in response to the Discussion Paper suggested that the 'incentive free' option warranted further analysis because it had the potential to remove the assessed inefficiencies associated with the existing HVDC charge, while avoiding wealth transfers from consumers to SI generators. It was also observed that it could be considered as an extension of the 'incentive-free' approach recommended as part of the postage stamp transition option.

C.1.5 TPAG has therefore developed a possible 'incentive-free' HVDC charging option, and considered a range of implementation issues.

C.2 A possible 'incentive free' allocation

C.2.1 In developing the 'incentive free' options TPAG has adopted the following objectives:

a) continue to charge the bulk of the HVDC costs to existing SI generators;

b) remove the competitive advantage for new generation development conferred on large incumbent generators in SI;

c) remove the competitive disadvantage for new SI generation relative to new NI generation;

d) remove incentives that discourage operating SI power stations at full output;

e) keep transaction costs low;

f) achieve a mechanism that is unlikely to fail in the face of creative restructuring.

C.2.2 In order to achieve objectives b and c it is necessary to allocate the HVDC costs to existing SI generators and not to new SI generators, and to achieve objective d it is necessary to allocate those costs in a manner that does not vary with production. Table 52 outlines the detail for a possible incentive-free charge to existing SI generators.

Table 52 The design of a possible 'incentive-free' HVDC charge

Feature	Design Detail
Forecast HVDC costs	• Forecast the annual costs of upgraded HVDC transmission (including pole 3) (cost of capital and operating costs). • Derive a fixed annual cost forecast covering (say) 25 years (or some other long-term period that is considered feasible). • Either index costs to CPI or incorporate an estimate in the forecast.
Allocate HVDC costs to existing SI generators	• Determine the HVDC charges by allocating the 25 year fixed cost forecast to existing SI power stations. • Allocate costs in proportion to HAMI over an historical reference period (say 2005-2010).
Link to power stations	• Determine that if a power station is sold or transferred to another entity that the fixed HVDC charge associated with that station must be transferred to the other entity. • Implement in a manner that ensures the HVDC charges remain with the revenue stream from generation and don't end up with a shell company without any assets or income.
Determining Interconnection charges	• Calculate the residual annual transmission 'interconnection' revenue requirement based on the following formula: *Interconnection revenue = Transpower revenue requirement – connection charge revenue – fixed HVDC revenue*

C.2.3 Under this design, recovering the annual costs of any future investment in HVDC assets and any HVDC costs beyond the chosen time period, would be incorporated in the residual calculation of interconnection charges.

C.2.4 There are several possible variants on this option, including the possibility of determining the 'fixed' annual cost to be allocated to SI generators on an annual basis rather than determining the charges in advance. However, TPAG considers the option described in Table 52 provides the best fit with the 'incentive-free' objectives.

C.3 Analysis

C.3.1 Under this 'incentive-free' option the existing SI generators would continue to be allocated HVDC costs, but would know in advance exactly what the charges would be over the chosen period (say 25 years) and it would be difficult for a SI generator to arrange its affairs in a manner designed to avoid or reduce the HVDC charge. The HVDC charges would not vary with production or new investment – meaning that there would be no incentives to withhold capacity and there would be no competitive advantages or disadvantages in the new generation market simply because of the HVDC charges.

C.3.2 Transaction costs should be low since the charges would be fixed in advance rather than calculated on an annual basis (apart from any indexation).

C.3.3 TPAG has identified a number of issues with this approach to an 'incentive-free' HVDC charge including:

- whether it is possible to implement a mechanism to ensure that charges remain with power stations. Does the Electricity Authority have the power to do this and would this need to be included in the Code or in the TPM guidelines?
- what happens to the HVDC charge if a power station is decommissioned. Is this a real problem or can it be ignored?
- whether the approach would resolve regulatory uncertainty, or create a powerful lobby to have the charge removed, thereby creating more uncertainty?
- whether it is good regulatory practice to allocate HVDC costs to existing SI generators while not allocating HVDC costs to future SI generators.

C.4 Conclusion

C.4.1 It is feasible to design an HVDC cost allocation mechanism that is 'incentive-free' in the sense that it removes incentives to withhold capacity and removes possible new generation competition advantages in favour of large incumbent SI generators and NI generators. However, it is possible that one set of negative incentives is simply replaced by another set of negative incentives for incumbent SI generators to lobby actively to have the charge removed on the basis that it is unfair (on incumbent SI generators relative to new SI generators) and arbitrary.

C.4.2 On the other hand, it could be argued that a 25 year fixed charge profile of costs allocated to existing SI generators is a very long term transition towards postage stamping the HVDC charges. Interpreted in this manner this incentive-free design is not entirely dissimilar to the postage stamp transition option.

Glossary of abbreviations and terms

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

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

TPTG	Transmission Pricing Technical Group
UNI	Upper North Island
USI	Upper South Island