Transmission Pricing Advisory Group

Summary of Submissions

TPAG discussion paper

25 July 2011

Version 2: This draft summarises the submissions on the TPAG discussion paper and is for TPAG review.

TPAG will need to give the submitter views due consideration, identify those comments which require further consideration, and provide guidance to the TPAG secretariat on how to take account of these comments in the TPAG analysis.

Highlighted comments
The TPAG secretariat has highlighted those issues that might require further consideration and has invited TPAG views on whether the comments are valid and if and how they should be taken into account. This is intended to assist TPAG in efficiently using its time at the 1 Aug meeting. However, members should not be constrained by the highlighted issues and should feel free to raise other points that they consider important to TPAG's considerations.

The secretariat has not highlighted issues that it considers are outside the scope of TPAG's terms of reference. In some cases, some issues have not been highlighted where related issues have been highlighted at other points in the report.

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

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1 Introduction and purpose of this report

1.1 Introduction

1.1.1 This paper provides a summary of submissions on the June 2011 Transmission Pricing Advisory Group (TPAG) Transmission Pricing Discussion Paper (Discussion Paper)[1].

1.1.2 This summary and the submissions will assist TPAG in preparing its advice to the Electricity Authority (Authority) on a preferred transmission pricing option.

1.1.3 The summary broadly follows the structure of the Discussion Paper. It summarises both submitters' responses to questions and other material provided by submitters. In each section of this summary the relevant questions from the Discussion Paper are given, but each section includes views from submitters that are pertinent to that section even if they were not part of a response to the relevant question. Where submitters repeated views these are, where possible given only once in the most relevant section of the review.

1.1.4 Full submissions and a table of submitter responses to questions are available on the Authority website[2].

2 Overview of submissions

2.1 Submissions received

Table 1 Submitters and topics submitted on by submitters

Submitter	Category	HVDC	Connection	Static Reactive Compensation
The Lines Company	Distributor	x	x	✓
Powershop	Retailer	✓	x	x
Transpower	Transmission	✓	✓	✓
Wel Networks	Distributor	✓	✓	✓
Pan Pac Forest Products	Large user	✓	✓	✓
Contact Energy	Generator/retailer	✓	✓	✓
Business NZ	User representative	✓	x	x
Carter Holt Harvey	Large user	✓	x	x
Meridian Energy	Generator/retailer	✓	✓	✓
Fonterra	Large user	✓	✓	✓
TrustPower	Generator/retailer	✓	✓	✓
Genesis Energy	Generator/retailer	✓	✓	x

[1] Available at: http://www.ea.govt.nz/our-work/consultations/advisory-group/transmission-pricing/

[2] Available at: http://www.ea.govt.nz/our-work/consultations/advisory-group/transmission-pricing/submissions/

Submitter	Category	HVDC	Connection	Static Reactive Compensation
Powerco	Distributor	✓	✓	✓
New Zealand Wind Energy Association (NZWEA)	Generator representative	✓	x	x
Mighty River Power (MRP)	Generator/retailer	✓	✓	✓
Grey Power Federation Energy Committee	Small user representative	✓	x	x
Norske Skog Tasman	Large user	✓	x	x
Orion New Zealand	Distributor	✓	x	✓
New Zealand Steel	Large user	✓	✓	✓
The New Zealand Refining Company (NZRZ)	Large user	✓	x	x
Electricity Networks Association (ENA)	Distributor representative	✓	✓	✓
Major Energy Users' Group (MEUG)	Large user representative	✓	✓	x
RTANZ	Large user	✓	✓	✓
Domestic Energy Users' Association (DEUN)	Small user representative	✓	✓	x
Vector	Distrbutor	✓	✓	✓
Vestas	Generator supplier	✓	x	x
Mainpower	Distributor	✓	x	✓

Notes:
1. MEUG has caveated its response saying its views should not be read as definitive as it considers that it has not had sufficient time to prepare comprehensive submission.
2. MEUG's submission included a commissioned report from NZIER.
3. ENA's submission was supported by Powerco
4. The following submitters gave their support or referenced parts of MEUG's submission: RTANZ, NZ Steel, NZRC, Norske Skog, Carter Holt Harvey, Grey Power.

3 TPAG's consideration of stage 2 analysis of the value of location-based price signals

Relevant question:

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

3.2 Submitter views

3.2.1 Most submitters that commented on this issue agree with TPAG's assessment (Contact, Fonterra, Meridian, MRP, NZWEA, Transpower, TrustPower and Vestas). Norske Skog responds that it 'probably' agrees, NZ Steel cannot, at this stage, see a demonstrable benefit, and Vector agrees that the analysis to date 'does not appear to provide a justification for introduction of full locational-pricing.'

3.2.2 In support of TPAG's assessment submitters note that:

a) TPAG's assessment was based on extensive analysis overseen by the Commission and the Authority using the GEM model. Analysis undertaken by the CEO Forum reached a similar conclusion (**Meridian**).

b) The main drivers for the analysis are the fact that new sources of generation are much more location specific and most of the significant transmission investments have already been made meaning there are few economic transmission investments to co-optimise (**Meridian**).

c) The location, extent and cost of resources will have more influence on the siting of new generation than any locational price signals in the transmission system (**NZWEA**, **Vector**).

d) Existing market locational signals such as nodal pricing will have some influence on new generation decisions (**NZWEA**).

e) The application of the Grid Investment Test (or any equivalent test established by the Commerce Commission) will also ensure that any major new transmission investment to capture a renewable energy resource that is currently inaccessible has demonstrated a net economic benefit (**NZWEA**).

3.2.3 Two submitters do not agree with TPAG's assessment: MEUG and RTANZ. These submitters raise the following concerns with TPAG's assessment:

a) That the models used are not fully stochastic and care needs to be taken in interpreting and relying on the results (**MEUG, RTANZ**).

b) Either a 'but-for' or deeper connection approach might realise most of the benefits identified (**MEUG**).

c) For future major refurbishment of new capital for HVDC assets, such as an additional submarine cable and filters, a locational pricing signal (eg capacity rights) could have benefits (**MEUG**).

d) The analysis suggests a benefit of $14m, yet TPAG's HVDC analysis indicates a dis-benefit of $14m to $51m from the locational signals provided by the HVDC charge. These two views appear to be in conflict (**RTANZ**, **Vector**). 'If locational-pricing of the entire transmission grid

> does not have a material impact on generation investment decisions Vector cannot see how the locational signal sent by the pricing of the HVDC link can have an impact on electricity generation investment decisions sufficiently material that its removal would result in "clear efficiency improvements".'

3.2.4 Pan Pac responds to questions 1 to 6 that the relevance of these questions was not important as 'normal commercial practice was not considered'. Pan Pac's view on how 'normal commercial practice should be considered is given in the summary of views on the analysis framework and HVDC analysis.

TPAG response to submitter views on TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investment decisions.

3.2.3(a): What is your view on this? What differences would you expect from a fully stochastic model?

3.2.3(d): Is this comment valid?

4 Regulatory context

Relevant questions:

4.1.1 Q2: Do you agree with the TPAG's assessment that the changes to the statutory framework during the course of the transmission pricing review project do not require the Commission's analysis and development of alternative TPMs to be reworked?

4.1.2 Q3. Do you agree with the TPAG's assessment that the options developed through stages 1 and 2 of the Review were developed in a manner consistent with the Authority's statutory objective?

4.2 Submitter responses

4.2.1 Most submitters that responded to these questions agree to both these questions (Contact, Fonterra, Meridian, MRP, NZWEA, RTANZ, Transpower, TustPower, and Vestas). Vector does not agree. Some submitters make comments that the Discussion Paper recommendations were not consistent with the Authority's statutory objective (**Norske Skog**, **MEUG** and **NZ Steel**).

4.2.2 Those submitters who agree made the following comments:

a) There appears to be a strong economic basis of analysis of the stages 1 and 2 that aligns with the new statutory objective of the Authority . On this basis Fonterra generally accepts that the former Electricity Commission's development of the alternative TPMs does not need to be reworked (**Fonterra**).

b) The analysis undertaken by the Commission in Stage 1 of the Transmission Pricing Review focussed on identifying current issues with TPM and possible options to address those issues based on efficient pricing criteria. In Stage 2 efficiency criteria was also used to assess the value of enhanced locational signals for economic transmission investment. These steps would also have been undertaken by the Authority under its decision-making framework (**Meridian**).

4.2.3 **Vector** repeats comments made in its submission on the stage 2 consultation paper that: 'The EA's narrower objective must have an impact on the analysis and evaluation in the transmission pricing review. When legislation shifts responsibility for a task from one organisation to another and the new organisation has a different statutory objective, it would be very unusual (and, *prima facie*, contrary to the will of Parliament) for that change to have no impact on the analysis, evaluation and decisions that are made regarding the task.'

TPAG response to submitter views on the regulatory context questions

4.2.3: Is there anything new to respond to in this comment? Does TPAG's view that changes to the statutory framework do not require the Commission's analysis to be reworked (because the Commission focussed on efficiency benefits during stage 1 and 2) still stand?

5 Analysis framework

Relevant question:

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

5.1.2 Eight submitters agree that TPAG had identified appropriate efficiency considerations (Contact, Fonterra, Meridian, MRP, NZWEA, Transpower, TrustPower, Vestas, ENA) and noting:

a) The considerations are a practical way to apply the concepts of dynamic, allocative and productive efficiency to the assessment of transmission pricing options (**Meridian**).

b) TPAG had done enough to enable useful cost benefit assessments (**MRP**).

c) The efficiency considerations represent a reasonable and practical means of assessing costs and benefits (**NZWEA, Vestas**).

d) That it is encouraging to see unintended efficiency impacts and good regulatory practice recognised prominently. 'Increasing complexity of itself can increase the scope for unintended negative efficiency effects, such as customer actions aimed at shifting costs for no net economic benefit and additional disputes over the interpretation of particular definitions.' (**Transpower**).

5.1.3 **Transpower** makes specific comments on the beneficiary pays consideration saying it agrees with TPAG's assessment that the benefits of any particular asset or set of assets can be different for different parties, and the value to those parties can vary over time. In Transpower's view, TPAG has correctly identified that:

a) when grid investment decisions are taken by a regulator, and hence those decisions do not rely substantially on private information, charging beneficiaries is much less likely to improve decision making;

b) there is little value to be gained from allocating sunk (or fixed) costs to beneficiaries; and

c) there is potential for any practical form of fixed and sunk cost recovery to create unintended price signals with negative economic effects.

5.1.4 MEUG, RTANZ and NZ Steel consider the efficiency considerations to be reasonable but suggest additional considerations, omissions or improvements. Norske Skog also suggests omissions.

a) None of the considerations cover the point that benefits need to unambiguously accrue to consumers to achieve the statutory objective of improving the long-term benefit of consumers (**MEUG**).

b) An additional consideration should be incorporated to reflect the demand-side ability to adapt to altered pricing (**NZ Steel**).

c) There is too little consideration of efficient use of electricity in the economy (**NZ Steel**).

d) 'A key concept of beneficiary pays has been completely missed by TPAG. At its most fundamental, a beneficiary pays assessment must look at who should have a rational willingness to pay for or contribute to an investment in the grid.' (**RTANZ**).

e) The TPAG seems to have forgotten the productive sector in its analysis. No consideration has been given to productive, allocative or dynamic efficiency effects on consumers (**Norske Skog**).

5.1.5 Vector does not consider that TPAG has identified appropriate efficiency considerations, noting:

a) TPAG has implicitly assumed there would be 100% pass-through of efficiency gains to consumers (**Vector**).

b) TPAG has also not taken into account that there would be ongoing uncertainty about whether there would be further changes to the TPM (**Vector**).

5.1.6 Vector's views of both these issues are considered in section 7.1.3.

5.1.7 Some submitters make general comments about TPAG's analysis framework.

a) The TPM is a schedule to the Code, so the Authority has an on-going obligation to ensure the TPM is fit for purpose and consistent with the Authority's statutory objective (**Meridian**).

b) **NZWEA** 'supports the robust and comprehensive approach that TPAG has taken in developing this paper and hopes that this can lead to enduring outcomes that allow all interested parties to move forward with investment and operating decisions with greater certainty.'

c) **Contact** supports the TPAG's use of the CAPs in order to ensure that any potential Code change that may result from their investigations aligns with the Authority's statutory objective.

d) **Pan Pac** submits that TPAG should have considered 'normal commercial practice' in which the cost of transport from a supplier (producer) to a consumer is paid for by the supplier.

5.1.8 Although **ENA** endorses the efficiency considerations, it considers the relevant starting point for analysis is the Electricity Commission's March 2006 decision on HVDC pricing.

5.1.9 In light of the importance of regulatory consistency to the overall credibility of the market, ENA submits that there should be substantial inefficiencies created by the current or modified allocation of HVDC charges to South Island generators, before the Authority concludes that there should be a shift in the incidence of charges

5.1.10 The ENA submits that the Authority should therefore adopt the following decision-making framework, which it submits is consistent with the CAPs:

i) Identify the inefficiencies associated with the status quo HVDC pricing arrangements;

ii) Identify within the status quo allocation whether there are modifications that could be made to reduce the extent of any identified inefficiency (e.g., the move from HAMI to MWh charging);

iii) Assess the materiality of any remaining inefficiency to determine whether it is material enough to consider a change in the incidence of HVDC charges (e.g., from South Island generators to loads); and

iv) Finally, consider the impact of a change in incidence on overall market credibility, and hence dynamic efficiency of the New Zealand economy, (which it considers synonymous with the long term interests of consumers).

5.1.11 ENA submits that the test in (iv) above is important. The New Zealand electricity market has been highly contentious, with numerous changes in market structure and governance arrangements due to lack of confidence in its ability to deliver sound outcomes to consumers. ENA considers that it is important that regulatory decisions, whilst recognising the importance of investor confidence, do demonstrably provide benefits to consumers. In ENA's view TPAG has not considered the extent to which the majority view takes into account how a change in incidence of HVDC charging would impact on market credibility and in light of the up to $1.2 billion shift in HVDC charges (NPV over 30 years), this is an important consideration.

TPAG response to submitter views on the analysis framework

Are comments 5.1.4 (a) to) (e)valid and do you consider that the efficiency considerations need to be improved or supplemented?

What is your view on 5.1.10 (iv)? Should market credibility and wider NZ economy impacts be considered as part of the analysis framework or are they already included?

6 Scope of TPAG's work

6.1.1 The Discussion Paper did not include questions on the scope of TPAG's work, but some submitters make references to the scope of TPAG's work and the direction that the Review is taking.

6.1.2 Submitters make the following comments on the focus of TPAG's work.

a) TPAG has focused the review on those elements of the methodology which may be suboptimal and hence where there may be a credible justification for change, and has restricted work to possible changes that are likely to be enduring **(Transpower)**.

6.1.3 Submitters raise the following concerns about the focus of TPAG's work.

a) **Vector** and **ENA** make comments that they had supported the Electricity Commission/Authority reviewing whether to extend locational-pricing beyond nodal pricing signals, connection charges and the current HVDC charge to the full transmission grid but were disappointed that the review has been allowed to 'morph from consideration of locational-pricing into yet another re-litigation of HVDC pricing.' Similarly **Genesis** has supported a review of locational signalling but not 'simply unwinding the 2007 decision'.

b) **Vector** considers that undertaking three reviews of HCVDC pricing in the space of just seven years, when the Electricity Authority has many other more important priorities, undermines regulatory certainty and rewards lobbying by vested interests. Similarly, **Genesis** and **ENA** considered that changing the HVDC charge would demonstrate receptiveness to lobbying.

c) **RTANZ** is disappointed with the focus of the TPAG on HVDC issues and considers that the TPAG has focused its efforts on repackaging old information. In RTANZ's view this meant that a wider consideration of the issue was not undertaken. Capacity Rights was dismissed due to time constraints and that discussion of connection asset issues was 'severely truncated' and little progress made.

d) **Genesis** considers that the current review has been a costly diversion for the Authority and market participants at a time when there are more productive work streams that could have benefited from greater urgency (for example, scarcity pricing, locational price risk management, demand-side participation, market information and the distribution contracting environment) (**Genesis**).

TPAG response to submitter views on the scope of TPAG's work 6.1.3: Has TPAG inappropriately focused in the HVDC issues?

7 Assessing options for HVDC cost allocation

7.1 Approach to summarising views

7.1.1 TPAG's assessment of options for HVDC cost allocation received the most comment, and the strongest comments from participants. This summary steps through submitters' views on:

a) The potential efficiency gains (section 7.1.3).

b) The range of options (section 7.3).

c) The assessment of options against the efficiency considerations (section 7.4).

i) Comments on the application of the efficiency considerations to the HVDC assessment

ii) Comments on the HVDC options

d) The assessment summary (section 7.5)

i) Whether change is justified (CAP 2)

ii) The comparison of the options (CAP 3))

iii) The transition options

7.1.2 Note that section 7.1.3 summarises submitter views on the analysis in section 6.2 and Appendix D of the Discussion Paper.

7.1.3 **BusinessNZ** does not state a view on the analysis and options for the allocation of HVDC costs, but has the following general concerns:

a) The on-going failure to resolve the HVDC pricing issue in a way that is durable and long-lasting has a potential impact on on-going regulatory stability.

b) The Authority needs to be extremely careful about avoiding politicisation of its decision-making processes, whereby market participants may be distracted from their core functions and lobbying the regulator is perceived as a profitable option. Core to this will be whether the Authority can convince a hypothetical disinterested, but fair-minded observer, reviewing the outcome in good faith, that the changes are efficient. It notes that if consumers object to the majority position it is possible that it is not in their long-term interests or they are mistaken and the Authority needs to clearly demonstrate what the benefits consumers will receive are, and why this makes the proposal worthwhile.

7.2 Submitter views on potential efficiency gains

Relevant question:

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

7.2.2 Submitters are split on whether there is sufficient evidence of a clearly identified opportunity for an efficiency gain to warrant analysis of alternative options. Contact, Meridian, MRP, Transpower, TrustPower, Vestas, NZWEA, agree. Fonterra agrees that there appeared to be a *prima facie* case that warrants further analysis, but does not agree with the assumptions and analysis. Other submitters, MEUG, Norske Skog, NZ Steel, RTANZ, NZRC do not agree. Others, whilst they did not provide a direct answer, question the assumptions and analysis contained in section 6.2 and Appendix D. Comments made by submitters are given below.

Comments in support of potential efficiency gains

7.2.3 Comments in support of the identification of potential efficiency gains are grouped as follows:

a) The rationale for the potential efficiency gains.

b) The robustness of the analysis.

c) The assumptions used.

d) The size or materiality of the efficiency gains.

e) Practical experience or evidence of inefficiencies.

f) Possible additional efficiency gains not adequately considered by TPAG.

The rationale for the potential efficiency gains

a) The current HVDC charge acts as a significant barrier to investment in SI generation projects (**Vestas**, **PowerShop**) or distorts the investment merit order (**TrustPower**).

b) The potential efficiency gains exist because of the unique treatment of the HVDC under the existing cost allocation, compared to interconnection assets. With a cost allocation solely to South Island generators, but an underlying group of beneficiaries much broader than just South Island generators, this will inevitably create inefficiencies (**Contact**).

c) The HAMI pricing methodology for the HVDC provides a significant locational cost as it identifies HVDC costs as the major difference (at the margin) between similar projects in each island (**MRP**).

d) Peak charging on generators is inappropriate as it creates disincentives on discretionary (and often only marginally economic) plant to meet peak demand (**MRP**). **Transpower** notes the effect that the HAMI allocation method has on the incentive to withhold peaking generation capacity at Manapouri, Roxburgh and Clyde. Transpower notes the argument in D.9 in that this withholding issue may largely be resolved by the commissioning of Pole 3.

e) Since market prices reflect the cost of new generation it's critical that market arrangements incentivise investment in the cheapest options, and don't create barriers to competition (**PowerShop**).

The robustness of the analysis

a) TPAG's analysis of the inefficiencies caused by the HVDC charge is conservative (**Contact**, **MRP**) and reasonable and pragmatic (**Contact**).

b) The analysis includes a comprehensive sensitivity analysis and scenario variation to test key assumptions (**MRP**, **Contact**).

c) The analysis can be viewed as an impact on the LRMC 'price path', or on the present value of the cost of generation (to meet demand) over time (**Contact**).

d) The discussion paper indicates that the outputs from the sensitivity analysis and scenario testing were relatively consistent (**Contact**).

e) The TPAG's work aligns with the Commission's analysis, identifying inefficiencies at the lower end of the range produced by the Commission (**Contact**).

The assumptions used

a) There are a wide range of factors that will influence the relative viability of a project. For this reason providing an equal playing field for generation investment in both islands is the best way of ensuring that the most cost effective projects reach the market (**NZWEA**).

b) While the modelling undertaken by the Commission's Transmission to Enable Renewables project did identify a larger wind resource potential in the NI, factors such as site scale, quality of wind resource, proximity to transmission assets and population density might make at least some of this SI resource more favourable than in the NI (**NZWEA**).

c) The analysis makes use of the SOO, an independently derived assessment of broad industry information about potential generation projects (**Contact**).

d) The investment merit order constructed to assess the benefit of moving away from the existing regime is too conservative. TrustPower has stated consistently over the past decade that it has South Island investment projects in its pipeline that would be economic, were it not for the DC charges. For the TPAG to assume that the vast majority of new investment over the next decade would be in the NI, is incorrect (**TrustPower**).

e) **Meridian** has recently completed a cost review of its pipeline of projects. The analysis agrees with TPAG's unit cost modelling contained in its analysis. Meridian includes a chart illustrating Meridian's anticipated unit cost ranges for a selection of generation options in the NI and SI.

f) The modelling assumes that the majority of new generation build in the next 5 to 10 years will be geothermal. However, the geothermal industry itself appears to be uncertain about the likelihood of this outcome, noting that projects beyond Te Mihi, Tahara and Ngatamariki are likely to be competing directly with wind[3] (**NZWEA**).

g) It is possible to take a less conservative view on the costs of wind that might see it move up the merit order (**NZWEA**). NZWEA included comments on the cost modelling of wind and increasing capacity factor. **Vestas** considered that the long range marginal cost of wind energy in the SI has been overstated, saying the Deloitte report[4] is a better guide.

7.2.3 "***The assumptions used***": Do you consider that the comments (b), (d), (f), and (g) are valid? Do you consider that TPAG should amend the assumptions used in the relative cost of generation options?

[3] http://www.energynews.co.nz/news/geothermal/6305/geothermal-cluster-proposals-due-next-month

[4] Economics of wind development in New Zealand, Deloitte for the NZWEA, April 2011. Available at: http://www.windenergy.org.nz/documents/economicsnz.pdf

The size or materiality of the efficiency gains

a) The benefits may be small, but they are not significantly overstated (MRP).

b) The outputs also indicated a consistency in terms of overall direction i.e. that the current HVDC cost allocation methodology (even under conservative assumptions) is inefficient (**Contact**).

c) The estimated NPV over 30 years of the locational risk proposal is between $38m and $77m (**Meridian**, **Contact**). The benefits are of the same order as other benefits quantified by the Electricity Authority to support recent regulatory intervention. Unlike the Electricity Commission's previous analysis on locational signalling, these benefits are clearly positive (**TrustPower**).

d) It would seem reasonable to consider this benefit, even relative to the total investment being made (**NZWEA**).

e) With conservative modelling being used it might also be considered that pursuing this opportunity would provide potentially significant 'option value' for the future (**NZWEA**).

7.2.3 "***The size or materiality of the efficiency gains***" : Do you consider that the comment (e) is valid?

Practical experience or evidence of inefficiencies

a) Some submitters (MRP, Contact, NZWEA, Vestas) note that they have observed a locational, peaking and direct grid connection penalty for SI generation projects. **Mainpower** refers to the current HVDC charges as a 'significant financial barrier to new generation opportunities in the South Island'.

b) TrustPower recently indicated that the likelihood of development (or expansion) of their Wairau hydro scheme, Mahinerangi (Stage 2) and Kaiwera Downs projects, for example, are all dependent to some extent on whether the existing cost allocation methodology still applies. Contact estimates that the existing HVDC charge could add around 10% to the long-run marginal cost of new South Island generation projects (**Contact**).

c) **Contact** submits that its operational management of peaking capacity from its Clyde and Roxburgh power stations is directly affected by the current HVDC cost allocation methodology. According to Contact, under certain hydro conditions, it could be incentivised to offer up to an additional 50MW of hydro peaking capacity under a non-distortive HVDC cost allocation methodology. Contact notes that the incentives are the same for other South Island hydro generators, who may choose not to offer peaking capacity in order to avoid increasing their relative HAMI contribution, consequently peaking capacity is then supplied by other, potentially more expensive, North Island generation.

d) **NZWEA** and **Vestas** refer to a recent report produced by Deloitte for the NZWEA which focused on the economics of wind development in New Zealand. That report used recent investment data from operational wind energy projects in New Zealand, and came to the conclusion that the current HVDC cost allocation added between $8 and $13 per megawatt hour to the cost of a wind farm project when compared to a project where no HVDC charges were incurred. 'Such a major cost impost can and does ruin the business case for many South Island projects that would otherwise be cost-competitive with equivalent projects on the North Island,' submits **Vestas**.

7.2.3 "***Practical experience or evidence of inefficiencies***": Do you consider that the comments (b) and (c) are valid?

Possible additional efficiency gains not adequately considered by TPAG

a) Removing barriers to new entrant south island generation investment may also stimulate wholesale market competition. This will further increase downward pressure on prices, which will ultimately have flow on benefits for end consumers (**PowerShop**).

b) TrustPower submits there could be improvements in competition in both the wholesale and retail markets that a move away from the existing DC charging regime would bring. As has been asserted in the Discussion Paper (consistent with TrustPower's experience), new entrant investors in South Island generation capacity currently face an investment disincentive relative to the incumbent generators. What has not been assessed clearly is how this advantage may manifest itself in opportunities to exercise market power in either the wholesale or retail markets, particularly in the limiting case involving a single South Island gentailer. Over time, the incumbents' advantage could lead to lower levels of competition than exist currently (**TrustPower**).

c) Given that the DC charges increase the long-run marginal cost of new-entrant South Island generation, TrustPower considers it is possible that a large proportion of the DC charges are currently being recovered through increased generator offer prices in the South Island. This is particularly likely for offers from peaking capacity, which are directly disincentivised to generate at efficient price levels by the HAMI charges. As a result of this, and the significant delay in South Island investment resulting from the existing regime, according to TrustPower wholesale prices for South Island customers are very likely to be have been increased substantially over efficient levels already. The proposed shift to postage-stamping will simply spread those charges out over all load, rather than just South Island load. Further, the high prices may be hindering load growth in the South Island, relative to the North (**TrustPower**).

d) If West Coast hydro were to proceed early enough there could be transmission cost savings (**Transpower**).

e) The current charging regime may also be leading to increased spill in the South Island. Because of the reluctance of peaking capacity to offer into the market at efficient price levels, other generators (those for whom the HAMI charges do not alter their operational incentives) are forced to hold more water in their reservoirs to ensure that they are able to generate to meet demand in peak periods. Maintaining higher levels of storage, on average, may lead to less-efficient placement of water than would otherwise be the case (**TrustPower**).

f) The HVDC costs create strong incentives for embedding projects in the South Island even though the reduced economies of scale of such projects reduce the project's benefits compared to a North Island alternative (**MRP**).

g) Practical examples of the inefficiencies associated with the status quo cost allocation mean that consumers will not be receiving appropriate signals as to the impact of their consumption decisions on investment in, and the operation of, key interconnection assets (**Contact**).

7.2.3 "***Possible additional efficiency gains not adequately considered by TPAG***": Do you consider that the comments (a) to (f) are valid? Do you consider that TPAG should amend the analysis of efficiency gains by estimating these additional efficiency gains?

Comments questioning evidence of an efficiency gain

7.2.4 DEUN, ENA, Fonterra, Genesis, Greypower, MEUG, NZSteel, Orion, RTANZ, TNZRC, Vector, Norske Skog, Pan Pac and WEL Networks do not agree that there is sufficient evidence of an efficiency gain that will be realised by customers.

7.2.5 Submitters concerns over the analysis of possible efficiency gains are grouped as follows:

a) General uncertainty that efficiency gains would be achieved.

b) The size or materiality of the gains.

c) The modelling approach used.

d) The assumptions used.

e) Doubts about whether efficiency gains would be passed on to consumers.

f) Evidence that there is investment in SI generation stations.

General uncertainty that efficiency gains would be achieved

a) The estimated efficiency gain is too uncertain to justify a regime that effectively gives SI generators the use of the link free of charge, by imposing an additional burden on all consumers, but especially those already struggling with the cost of the power they need (**DEUN**). Other submitters: **Vector**, **RTANZ**, **Fonterra**, **NZ Steel**, **MEUG**, **Genesis**, **Grey Power** also commented on the uncertainty that benefits would be realised by consumers.

The size or materiality of the gains

a) There are problems reconciling that the TPAG concluded that locational-pricing of transmission would not materially influence generation investment decisions yet concluded the opposite in relation to the HVDC link when the size of the benefits were similar (**Vector**).

b) The quantified benefits of moving from a more efficient charging approach ($/MWh injected in the South Island) to shifting the HVDC charge on to consumers are estimated to be between $7-$39 million net present value ("NPV") over thirty years. By way of contrast, we estimate that the NPV of increased charges to consumers of a changed incidence of HVDC charges could be up to $1.2 billion over 30 years, and even under a transition arrangement, consumers would ultimately become liable for more than $100 million in HVDC charges per annum (**ENA**).

c) The possible unintended efficiency impacts identified by TPAG are immaterial when compared with the present value of future generation investments (**Orion**, **Genesis**, **RTANZ**).

d) The magnitude of the benefits are within the margin of error (**Norske Skog**).

7.2.5 "***The size or materiality of the gains***": Do you consider that the comments (b), (c), and (d) are valid? Do you agree that the magnitude of the efficiency benefits is immaterial when compared to the present value of future generation investments?

The modelling approach used

a) The modelling tools are, in spite of their mathematical complexity, still simplified abstractions of reality (**ENA**).

b) Investment efficiency based on LRMC ignores the impact that new generation has on SRMC and therefore the timing of new investment (NZIER for **MEUG**).

c) Dynamic efficiency needs to be measured in terms of impacts on consumers, and therefore the sum prices/costs to consumers over time; the comparing the LRMC of investment with and without the HVDC charge does not do this (NZIER for **MEUG**) as any reduction does not necessarily translate to lower prices for consumers.

d) Modelling the generation that a central planner with perfect information would build, even with random but systematic variations to input parameters, does not provide insight into generation investment decisions likely to be made by investors facing competition, information limitations and a range of uncertainties (**Genesis**).

e) Spreadsheet models are used and have weaknesses (**RTANZ**, **Norske Skog**). Norske Skog submitted that a spreadsheet model:

   i) is limited to computing a number of scenarios and comparing. A linear programme would use an algorithm to find an optimal solution;

   ii) is difficult to follow and the methodology not plainly laid out, a mathematical formulation is easy to follow; and

   iii) is not readily scalable.

f) The approach does not handle uncertainty appropriately as 'non-anticipativity of exogenous parameters should be included' (**Norske Skog**). Norske Skog's submission contains more detail on alternative modelling approaches.

g) The modelling work has not been subject to any external and impartial audit or validation (**RTANZ**).

7.2.5 "***The modelling approach used***": Do you consider that the comments (a) to (f) are valid? Do you agree that there is a problem with using an LRMC approach to identify efficiency gains? Do you agree that the spreadsheet model has limitations that mean the approach is deficient? 7.2.5(g) is there a need to externally audit the modelling work?

The assumptions used

7.2.6 **MEUG** commissioned a review of the Appendix D analysis by NZIER. The NZIER views are supported by a number of submitters as well as MEUG: Carter Holt Harvey, RTANZ, Norske Skog, NZRC.

7.2.7 NZIER makes the following comments on the assumptions used by TPAG and considers:

a) TPAG has inappropriately assumed that the minimum effective investment hurdle for all generators is $35/kW/yr. In NZIER's view a more appropriate assumption is that any project that is more than $13/kW/yr cheaper than NI generation is expected to be undertaken. This reduces the expected NPV cost to $6 million for inefficiencies of suppressed baseload generation and reduces the estimated inefficiency of suppressed peaking generation to $2.6m.

b) That the inefficiency from withholding existing peaking capacity is eliminated as the Discussion Paper argues at paragraphs 6.2.30 and D.9.5 in Appendix D that once Pole 3 is commissioned greatly improved access for South Island generation to the higher-priced North Island peaking market should overcome the HAMI charge and thus most if not all South Island peaking capacity will be offered.

c) That the anticompetitive effects from advantaging Meridian are less likely than implied.

d) The capital costs for each generation project only include direct connection costs – not grid investments that get triggered as a result of building a power station in remote places.

e) It is not clear if the 24 scenarios reported in TPAG Table 41 are equally likely, or if some particularly unlikely scenarios are biasing the average up or down.

7.2.8 Other submitters' comments on the assumptions used in the Discussion Paper are:

a) There are a number of factors that impact on investment decisions (paragraphs 6.5.17-18) of which the HVDC charge is one small component (ENA). Insufficient weight is given to other factors such as demand, retail/generation ratios, structure of portfolio, contractual exposures, ETS costs (**NZ Steel, Fonterra**). Fonterra has attempted to understand what level of disorder in the merit order is needed for the benefit to consumers to be lost. A number of credible alternative scenarios are considered by Fonterra using a simplified merit order model that, in Fonterra's view, show that some of these real world influences will remove all benefit to consumers that TPAG have proposed and that the effect of removing the HVDC charge from SI generators is immaterial. (Fonterra suggests in more detailed analysis in its submission that under various credible alternative scenarios, the benefits fall to zero and the NPV can even become negative.)

b) The wide range of efficiency gains ($11m to $96M NPV) suggested in the TPAG majority report indicates significant variability in the model output which in itself throws considerable doubt on the potential values suggested (**Carter Holt Harvey**).

c) The modelling assumes no offsetting improvements in transmission investment would arise from beneficiaries (South Island generators) bearing the costs of HVDC investment and does not model deadweight losses from increased electricity prices (**Genesis**).

d) The modelling does not include any scenarios where further HVDC investment is required even though this is a plausible scenario (**Genesis**).

e) There are other factors other than the HAMI allocation in decisions to offer peak capacity or invest in peaking capacity (**NZ Steel**). NZ Steel considers Meridian's position and factors that might influence its incentives such as exposure to one very large customer, restrictions imposed by on lake level guidelines, resource consent difficulties, water management arrangements for the Waitaki system and HVDC capacity issues.

f) The analysis ignores a good reason why NI generation is built and will continue to be built – the abundance of wind and geothermal and the location of the bulk of the demand in the upper NI (**NZ Steel**).

g) The HAMI allocation can be adjusted under grid emergency rules (**NZ Steel**).

h) **RTANZ** is also concerned that the allegations that generators are withholding peaking capacity point to an element of gaming the system where generation is withheld so the System Operator is forced to call on it under grid emergency rules and waive collection of HVDC charges.

i) The argument that large incumbent SI generators have an investment advantage over smaller and new entrant generators derives from a miss-specified counterfactual (**RTANZ**). RTANZ has included examples in its submission. RTANZ argues that regardless ' there is nothing that should be done to an efficient cost allocation to alleviate this imagined problem'.

7.2.7: Do you consider that the NZIER comments on the assumptions used are valid? In particular, do you agree that the counterfactual is wrong and that the anticompetitive effects from advantaging Meridian are probably less than implied?

7.2.8: Do you consider that the other comments on the assumptions used are valid? Do agree you that the analysis subscribes insufficient weight to other uncertainties? Do you agree that the modelling should incorporate the possibility that further investment in the HVDC is required?

Doubts about whether efficiency gains would be passed on to consumers

a) Even if there are efficiency benefits from a move to postage stamp pricing, it is not clear the extent to which these would be passed-through to consumers (**Vector, Carter Holt Harvey**).

b) The likelihood that any minor efficiency gain would translate to lower prices to consumers is low in market where market power is exercised by generators either through the use of transmission constraints or in times of tight winter fuel supplies. The projected reduction in prices should be heavily discounted from a long term consumer benefit perspective (**ENA**).

c) There is no incentive for SI generators to reduce their prices proportionally to account for the removal of the HVDC charge (**Powerco**). NZ Steel does not expect SI generators to offer in their stations at lower prices. The short run marginal cost of South Island hydro generation is basically zero **(NZ Steel**). NZ Steel rejects that the costs are linked to offer behaviour as NZ Steel claims the Discussion Paper would elsewhere suggest.

d) The extent to which benefits to customers might occur would depend on whether South Island generation would set wholesale (spot) electricity prices, i.e. be the marginal generator. We would expect spot prices in the South Island to be based on the marginal generator's price and therefore generally based on the long-run marginal cost (LRMC) of North Island thermal generation investment (**Orion**). If the bulk of new South Island generation would be wind and hydro, which history, the GEM model, and fuel availability suggests would be the case, then there may be little or no pass-through of efficiency gains from South Island generators (**Vector**).

e) Lower average wholesale prices will only occur if these investments displace higher variable cost power stations – generally thermals. If thermal stations remain the marginal price-setters for a similar number of trading periods over the future as they do now, there is no reason to believe wholesale prices will reduce at all. In these circumstances, consumers will see no reduction in prices. This is a perfectly likely scenario (**RTANZ**).

f) The implicit TPAG assumptions about the impact of movements in the LRMC curve on SRMC which drives wholesale prices are very questionable (**RTANZ**, **Norske Skog**). Norske Skog has plotted the LRMC of a CCGT overtime and compared with average spot prices at Haywards and asserts that there is no evidence for a relationship between LRMC and spot prices. **NZIER** made similar comments that LRMC modelling has limited capacity to infer spot prices.

7.2.8 "***Whether efficiency gains would be passed on to consumers***": Do you consider that the comments are valid?

Evidence that there is investment in SI generation stations

a) Meridian has not been disincentivised from further SI investment. It has announced plans and received resources consents to build on the Pukaki-Ohai canal (**NZ Steel**).

7.3 Submitter views on the range of HVDC options

Relevant question

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

7.3.2 Contact, Fonterra, Meridian, MRP, NZWEA, Transpower, TrustPower and Vestas agree with the range of HVDC options identified for assessment, although Fonterra also suggests that, should the flow-trace option be adopted for AC assets, and the HVDC charges be allocated to consumers, TPAG should also consider flow trace for the HVDC.

7.3.3 MEUG (and NZIER), Norske Skog, NZRC, comment that there was insufficient analysis of the incentive-free allocation to SI generators. Norske Skog and RTANZ consider the capacity rights option had not been given sufficient consideration. The concerns raised in regards to these options are considered in section 7.4.

7.3.4 Submitters suggest the following options should be considered:

a) Other structural options such as the use of a load factor weighting that reduces the charge to low load factor generation, or restructuring the charge so that generation during peak demand periods incurs a lesser HVDC charge (**RTANZ**).

b) A phased allocation to all generators (**WEL Networks**). In WEL Networks' view this will have the same effect as reallocating them to all NZ distributors but without the customer having to face a mandatory set of phased increases in line prices. The effect this will have on generation prices will not be discerned by nor be capable of being measured by customers. Further, reallocating the HVDC cost proportionally to all NZ generators instead of NZ distributors will achieve the same desired investment and efficiency signals wanted by the TPAG.

c) Allocating the existing HVDC link to existing SI generators, and new HVDC as postage stamp (**Vector**).

d) Delaying a decision on (or implementation of) postage stamp pricing of the HVDC link for 10 years (**Vector**) given that the expected material deferment of cheaper SI generation does not occur until about this time .

TPAG response to submitter views on range of options 7.3.4 Do you consider that any of the alternative HVDC options suggested by submitters should be assessed by TPAG?

7.4 Submitter views on the assessment of the HVDC options against the efficiency considerations

Relevant question

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

7.4.2 This section summarises submitters views on:

a) overall, whether submitters agree with the assessment;

b) comment on the application of individual efficiency considerations; and

c) comments on the assessment of each option

Overall submitters views of the assessment

7.4.3 Contact, Meridian, NZWEA, Vestas agree with the assessment. MRP and Transpower generally agrees.

7.4.4 TrustPower considers that elements of the assessment were too conservative.

7.4.5 Submitters that do not agree that there is a clear efficiency gain (see paragraph 7.2.2), do not agree with the subsequent assessment, as the assessment draws on the analysis of the efficiency gain. (MEUG (and NZIER in its report), Norske Skog, RTANZ, Fonterra, NZRC, NZ Steel, Vector, Genesis).

Comments on the application of individual efficiency considerations

Efficiency consideration 1: Beneficiary pays

7.4.6 Submitters who generally support TPAG's application of the beneficiary pays approach to the HVDC make the following comments:

a) The HVDC has become an interconnection asset and, as such there is no practical way of robustly applying a beneficiary-pays model to it (**MRP**).

b) TPAG's point that charges for the other parts of the interconnected grid are not levied on a beneficiary pays basis is also valid, and whether or not it is easier to identify the beneficiaries of the HVDC link than the beneficiaries of parts of the interconnected grid seems to be an increasingly moot question (**Transpower**).

c) Following the HVDC upgrade the transmission constraint will not be the link, but the AC system of the lower North Island. From an industry wide perspective it would therefore seem more appropriate to treat the DC link as just an extension of the transmission grid (**Powerco**).

d) In Transpower's view, South Island generators and/or North Island customers are not only the primary beneficiaries in very wet periods but also during normal weather periods. Nevertheless, this is a largely academic point, as substantial further investment will not be required for many years (**Transpower**).

e) The functions that the interisland HVDC link performs have changed significantly over time. TPAG has acknowledged the role the link plays in wet and dry years transferring electricity between both islands as well as providing a number of critical interconnection benefits to the system as a whole. These interconnection benefits to all grid users are likely to be even greater with the new capacity and functionality offered by the pole 3 upgrade (**Meridian**).

f) Transpower considers that the conclusion in favour of some form of postage stamping follows inevitably if the HVDC link is treated as a sunk or fixed cost, but notes that at some stage in the future the beneficiary pays argument may arise again if new investment in the link is required (**Transpower**).

7.4.7 Submitters who generally do not support TPAG's application of the beneficiary pays approach to the HVDC make the following comments:

a) A robust and objective identification of beneficiaries of the HVDC is imperative if change to HVDC pricing is to be accepted by the wider industry. Whilst we can accept that not all is always black and white in the world, particularly given its "different states" the fact is that the status quo is the status quo and factors such as beneficiary identification are too important to leave open if one is trying to make a case for change (**NZ Steel**).

b) RTANZ considers there is no assessment of 'willingness to pay' arguments which ultimately should drive all investment decisions. In RTANZ' view, the only parties with a rational willingness to pay for the HVDC assets are South Island generators. This is so their investments can generally receive the higher prices set by more expensive North Island thermal stations. (**RTANZ**). NZIER in its report for MEUG also made comments on willingness to pay in regard to the incentive free option: 'If existing SI generators only would have voluntarily agreed to long-term contracts between the transmission service provider and others, in a world which free riding and hold-out are not possible, then sufficient willingness to pay from existing generators is all that is required on efficiency grounds. There is not a requirement on economic efficiency grounds for new entrants to 'pay their fair share' over and above what is being paid for by existing beneficiaries, as the asset is sunk; the return on investment to Transpower is already sufficient; and locational constraints are adequately signalled in the market price (D.2.1).' (NZIER for **MEUG**)

c) **RTANZ** reviews the Commission's main drivers for approving the HVDC GUP investment in some detail in its submission which it submits indicate that the investment is principally about serving the needs of SI generators. RTANZ notes:

   i) that much of the Pole 3 investment restores the capacity of the HVDC link to that which existed prior to the partial retirement of Pole 1 and therefore there is a large element of replacement in the investment; and

ii) Transpower initially proposed the investment as a reliability investment, but the Commission advised Transpower that it should be considered an economic investment because the primary effect of the investment was not to reduce expected unserved energy.

d) TPAG's claim that the investment efficiency benefits from applying a beneficiary-pays approach to HVDC allocation are likely to be relatively small misses an important point that allocating costs to beneficiaries, who have a willingness to pay, provides an important investment and cost-allocation signal for all participants (**RTANZ**).

e) There is another investment under consideration for a new subsea cable and the efficiency of that decision may be improved if SI generators are allocated the costs (**RTANZ**).

TPAG response to submitter views on the application of the beneficiary pays considerations

7.4.7 (a): Do you agree that a "robust and objective identification of beneficiaries of the HVDC" is necessary? Do you think this is feasible?

7.4.7 (b): Do you agree that the only parties with a rational willingness to pay for the HVDC assets are SI generators?

Efficiency consideration 2: Locational price signalling

7.4.8 Submitters make the following comments:

a) The link provides some incentive for new generation to be established on the North Island and therefore closer to areas of highest demand (**NZ Steel, Powerco**), reducing system losses to a more economically optimal level (**Powerco**).

b) The HVDC charge is no more an inefficient locational price signal than investment in connection assets by a remote generator (**RTANZ**).

TPAG response to submitter views on the application of the locational signalling consideration

7.4.8 (b): Is this comment valid and do you agree that the HVDC charge has similar characteristics to connection charges for remote generators?

Efficiency consideration 3: Unintended efficiency impacts

7.4.9 Submitters make the following comments (for other relevant comments see section 7.1.3):

a) All of the alleged impacts discussed relate to the structure of the charge, rather than the allocation to SI generators (**RTANZ**).

TPAG response to submitter views on the application of the unintended efficiency impacts consideration 7.4.9: Is this comment valid?

Efficiency consideration 4: Competitive neutrality

7.4.10 Submitters make the following comments:

a) Competitive neutrality cannot be assessed in the abstract but must be looked at and weighed with the range of relevant factors brought to bear (**NZ Steel**).

b) Leaving HVDC costs where they lie does not necessarily target particular generation technology or companies or company sizes. They are a factor of where the resource and hence the generation is versus where the load is (**NZ Steel**).

TPAG response to submitter views on the application of the competitive neutrality consideration 7.4.10 (a): Is this comment valid?

Efficiency consideration 5: Implementation and operating costs

7.4.11 Submitters make the following comments:

a) These would dictate retaining the status quo (**NZ Steel**).

TPAG response to submitter views on the application of the implementation and operation costs consideration

Efficiency consideration 6: Good regulatory practice

7.4.12 Submitters' comments on the application of this efficiency consideration are grouped under the different aspects of good regulatory practice identified by TPAG.

7.4.13 Consistency over time

a) NZ Steel submits that good regulatory practice requires a clear mandate to make changes. Investment decisions have been and are being made all the time, including those around generation investment and location of new industrial demand. A dramatic shift in HVDC charging will not provide the consistency of outcome that consumers are entitled to expect and that is required for any new economic investment by industry (**NZ Steel**). **Genesis** and **Orion** argue similarly that any change requires a clear material improvement.

b) Removing the HVDC charge would be inconsistent with good regulatory practice. The current transmission pricing methodology was settled in 2007 following a decade of dispute and there has been no material change in circumstances to prompt revisiting the pricing methodology now (**Genesis**). Every cost allocation methodology has imperfections, so there should be a preference for stability and consistency over time. This is reinforced by the provisions in the Code governing reviews of the transmission pricing methodology (clause 12.86 sets out that the Authority may only review an approved transmission pricing methodology if it considers that there has been a material change in circumstances.)

7.4.14 Durability

a) We are concerned also at the durability of any change as we expect a change to attract dispute intervention of the type mentioned in section 4.3.19(b) of the Discussion Paper (either through the regulator, the courts or by Ministerial intervention) (**NZ Steel**). Vector makes a similar point: 'consumers and consumer groups would be highly motivated to lobby for further amendments given the immediate negative impact on them… Any generator considering investing in SI generation, on the basis that removal of HVDC charges on SI generators makes the generation commercially-viable, would need to take the risk of further changes to the TPM into account in its investment decision.' (**Vector**)

b) MRP does not agree with the assessment of durability for the HVDC costs. Any future challenge is likely to be motivated by the desire to avoid costs, and any allocation methodology that unavoidably distributes significant costs will always create incentives to challenge the allocation. However, only a robust, principles and defensible regulated decision can offer durability (**MRP**).

7.4.15 Consistency over the grid

a) In RTANZ's view it is entirely consistent to treat the allocation of costs associated with different assets to different beneficiaries. All that is required is that the approach is principled and consistent. In RTANZ's view the allocation of HVDC costs to South Island generators clearly meets this test, being both principled and consistent, and it matters not one bit that other assets are allocated differently (**RTANZ**).

b) The Pole 3 costs should not be allocated to South Island generators. The economic role of Pole 2 is less clear but a methodology that treats assets that have similar economic properties differently is unsustainable (**MRP**).

TPAG response to submitter views on the application of the good regulatory practice consideration 7.4.15 (a): What is your view on this comment?

Comments on the assessment of each option

7.4.16 This part of the summary brings together submitter comments on the options assessed by TPAG, whether the comments were around the assessment of the options against the efficiency considerations or other more general comments. However other parts of this summary are relevant to the views of different options (for example, sections 7.1.3, 7.4).

Capacity rights

7.4.17 A number of submitters comment that more consideration should be given to the Capacity Rights approach (RTANZ, NZ Steel, MEUG, Norske Skog) giving the following reasons:

a) There is such brief detail on the minority view of capacity rights that it is not possible to give a view on it (**NZ Steel**). NZ Steel particularly wanted to know the minority view on the cost and ease of implementation.

b) That capacity rights was dismissed because of time constraints (**RTANZ**).

c) If a decision is made to postage stamp the HVDC, then it would be difficult in the future to implement capacity rights because of wealth transfers to consumers from SI generators. Closing off the pathway to adopting capacity rights removes potentially significant real options benefit from further market reform (**RTANZ**).

d) That capacity rights, by its nature, discovers who is willing to pay for the HVDC (**RTANZ**).

e) The primary benefit of the capacity rights option is that it provides a strong economic efficiency foundation for making investments in the HVDC link. The TPAG CBA has not focused on this issue on the basis that pole 3 is for all intents and purposes now sunk and TPAG assume that no further investment is required for at least 10 years (D.9.6) (NZIER for **MEUG**).

f) The capacity rights option would have all of the benefits of the postage stamp options in that the pricing for the link would be allocatively efficient, and thus not distort efficient investment decisions in baseload and peaking generation (NZIER for **MEUG**).

g) There appeared to be undue reluctance to score capacity rights relative to the other options, but the explanations provided in the TPAG document appear sufficient to do so. In NZIER's opinion, the generation and peaker investment efficiencies should be larger than other options (**NZIER for MEUG**).

h) The Electricity Authority recently estimated that an FTR market would cost between $2.4 and $4.8 million to implement. Quite why capacity rights should be a factor of 10 higher is difficult to comprehend (**Norske Skog**).

i) Norske Skog does not understand how the TPAG's comments about HVDC Capacity Rights in Table 23 (which appear to be simple guesses) can be used to dismiss this option (**Norske Skog**).

7.4.18 Submitters raise the following concerns about capacity rights:

a) It is likely to further complicate the New Zealand electricity market and carries with it the risk of failing to deliver Transpower's revenue requirement in respect of the HVDC (**ENA**).

b) The complexities associated with creating the process to identify those parties will to pay for the HVDC, and with trying to introduce it to the New Zealand market, significantly reduce its value in practical terms. (**Contact**).

c) The HVDC capacity rights option would be heavily reliant on a robust secondary market for the trading of capacity rights, which may introduce risks around the concentration of those rights (**Contact**).

d) The inability of the TPAG to quantitatively assign benefits to offset these significant costs is likely to reflect the theoretical nature of the benefits. For example, while those that value capacity would potentially be able to bid to acquire that capacity, an additional process for capacity allocation during emergencies would also have to be created in case those that could provide support (reduced load or additional generation for example) did not hold capacity, yet required access to it to help maintain the integrity of the electricity system (**Contact**).

e) The potential benefits of a capacity rights option may be more readily identifiable in an environment where HVDC capacity was constrained but this is not likely to be the case for 20 – 30 years (i.e. until additional HVDC capacity is required) (**Contact**).

f) A capacity right determination process for the HVDC may be beneficial in a market where rights to all transmission assets were determined in this way, but this is not the case, and is unlikely to be the case in New Zealand in the foreseeable future. In the same way that treating the HVDC differently to other interconnected transmission assets currently creates inefficiencies (as concluded by the TPAG), applying a capacity rights process to the HVDC is also likely to create inefficiencies (**Contact**).

7.4.19 Although **ENA** had concerns about a capacity rights option it, suggested that if the Authority does shift the incidence of the HVDC charge to consumers that consideration be given to an approach whereby, on behalf of consumers, a new market entity is established to operate the link as a merchant inter-connector. The difference in prices between islands would be used to defray some of the cost of the HVDC. This would potentially result in only modest additional complexity to the market, but could mitigate the impact of HVDC charges on consumers.

TPAG response to submitter views on the assessment of capacity rights 7.4.17: Should TPAG have given more consideration to Capacity Rights? Should it now give more consideration to Capacity Rights?

Postage stamp

7.4.20 Submitters gave the following reasons for supporting the postage stamp option:

a) It appropriately treats the HVDC like other interconnected transmission assets (**Contact**).

b) It will better allow consumers to understand the full opportunity cost of their consumption decisions, leading to improvements in investment and operational decisions for those assets (**Contact**).

c) Postage stamping recognises that the ultimate beneficiary of the asset is the consumer. While these customers may be limited in their ability to interact in the decision making process for new investment, at a minimum it cannot be worse than the status quo (**Contact**).

d) It does not require the complex processes associated with the capacity rights option (**Contact**).

e) The investment inefficiencies inherent in the status quo would be eliminated (**Contact**).

f) The removal of the HAMI determination would also eliminate the investment and dispatch inefficiencies inherent in the status quo cost allocation methodology (**Contact**).

g) The concerns noted around immediate and certain up-front transfers of value (compared to future expected wholesale price reductions) are not relevant. Most actions in the wholesale market require such trade-offs, particularly in terms of investment in generation capacity, which are hugely capital intensive (up-front) yet rely on expectations of price. If these concerns are real, then it raises questions about the suitability of a number of the Authority's priority projects (e.g. the FTR proposal, scarcity pricing) which are likely to result in certain up-front costs, with the expectation of long-term benefits that more than offset them (**Contact**).

7.4.21 Submitters raise the following reasons against the postage stamp option:

a) At the extreme, allocating costs to consumers directly is akin to arguing that no generator should ever pay connection asset costs either, lest some low cost generation investments remote from load be displaced by higher cost investments located closer to load (**RTANZ**).

b) At present the South Island generators pay directly for this link which was installed for the purpose of transmitting electricity generated in the South Island to its main market the North Island. Ultimately all consumers pay the cost of operating this link. As this cost is already integrated into the total cost of the energy consumed at present. To now suggest that the cost of operating this link should now be charged directly to the consumers does not make a lot sense for the consumer, only to the generator (**Grey Power**).

7.4.22 A number of submitters provide estimates of the extent to which consumers or larger users would see price increases or wealth transfers. These are considered in the section 7.9 after the summary of submitters' views on the transition options as they concern a mixture of price impacts from postage stamping and transition to postage stamp.

TPAG response to submitter views on the assessment of postage stamping 7.4.20 (g): Do you agree that value transfers should not be taken into account?   7.4.21 (a): Is this comment valid?

MWh allocation to South Island generators

7.4.23 Submitters raise the following points on the MWh allocation:

a) In NZIER's view in its report for MEUG, the upper benefits of the MWh option have been significantly underreported. TPAG report that the range of efficiency improvements under an MWh charging arrangement fall between \$10m–\$12m (6.4.47), based on the bottom two right-hand cells of Table 42 (page 141). However, in every other area of analysis TPAG reports the largest and the smallest effects for any one scenario. Treating this item consistently with the remainder of the analysis increases the range of benefits of the MWh allocation to \$3m–

$29m (the upper bound relating to 'Random Capex 6' and the lower bound 'Random Capex 7') (NZIER for **MEUG**).

b) There may be enhancements of the MWh-based approach which result in further efficiency enhancements, for example, adopting a three-year rolling average to determine charges (**ENA**).

c) Like the HAMI charge, the MWh charge on generation would also have impacts on dispatch efficiency. If a charge of $x/MWh were levied on every unit of generation, this would incentivise South Island generators to spill energy rather than generate when spot prices were lower than $x. This would lead to a large inefficiency, particularly with more wind and hydro capacity being built in the South Island (**TrustPower**).

d) A MWh allocation to South Island generators would make no difference in terms of the beneficiary pays efficiency principle compared to the status quo (**Contact**).

e) A MWh option would continue to impair the relative economics of South Island generation projects, albeit to a lesser extent than the status quo (**Contact**).

TPAG response to submitter views on the assessment of the MWh option

7.4.23 (a): Do you agree that the upper benefits of the MWh options have been underreported?

7.4.23 (b): Do you agree that variants on the MWh option should be considered?

7.4.3 (c): Is this comment valid?

Incentive free allocation to SI generators

7.4.24 A number of submitters raised concerns that the 'incentive-free' allocation had not been adequately considered by TPAG, and recommend further work. (NZIER for MEUG, ENA, RTANZ, Norske Skog, NZR, Vector). Submitters gave the following reasons:

a) The option is evaluated against each efficiency area but it not reported in the TPAG summary table 27 with the reason given that it is unworkable. TPAG does not explain why it is unworkable and if it were, why it was evaluated with the other options (NZIER for **MEUG**).

b) TPAG Table 20 provides some explanations as to why this option may be unfair to existing SI generators if new entrants did not 'pay their fair share'. However, notions of fairness or unfairness are not aspects able to be included in pure CBA, which is the basis of the CAP 2 and CAP 3 assessments. The Authority's CAPs are limited to economic efficiency (NZIER for **MEUG**).

c) The incentive-free allocation is, according to TPAG (Table 23), the only option that does not distort dispatch or investment decisions (**Norske Skog**).

d) Table 20 implies that existing South Island generators might complain about it, but complaints by participants do not justify violating the CAPs (**Norske Skog**).

e) TPAG notes that this option avoids the risk of disadvantaging small and new entrant generators. Moreover, small and new entrant generators do not have an advantage at the margin over incumbent generators (NZIER for **MEUG**).

f) SI generators are obviously comfortable with an 'incentive-free' approach as part of a transition process (**RTANZ**).

7.4.25 Submitters raise the following concerns with the incentive free option:

a) It will not produce any benefits (compared to the status quo) in terms of ensuring beneficiaries of the HVDC pay for the right to those benefits (**Contact**).

b) It may be worse (in terms of inefficiencies) than the status quo, in that it will treat existing and new South Island generators differently (**Contact**).

c) It is likely to be low cost, but difficult to implement (or change) as its differential treatment of the HVDC (compared to other interconnected transmission assets) is highly likely to lead to dispute (**Contact**).

TPAG response to submitter views on the assessment of the incentive-free option 7.4.24: Should TPAG give further consideration of how an incentive-free option could work?

Postage stamp transition

7.4.26 This section of the summary of submissions provides submitter comments on postage stamp transition options generally. Section 7.7 summarises views on the different transition options.

7.4.27 Submitters that support a transition to postage stamp option make the following comments in support of the option:

a) It is a practical solution as it is non-distortionary and the transition provides for a good balance between the competing principles of price stability and a robust reallocation of HVDC costs (**MRP**).

b) Meridian's operating costs would reduce if there was a shift to postage stamp pricing. However, Meridian would also receive lower wholesale revenues under postage stamp pricing due to the entry of additional SI generation from that likely under the current pricing methodology (**Meridian**).

c) The Authority is tasked with seeking the outcome which best serves the long term interests of consumers. Meridian accepts that the Authority should seek to avoid abrupt transitions from the current pricing arrangements (**Meridian**).

d) The implementation costs are likely to be low (**MRP, TrustPower**).

e) The proposed change is most likely to confer overall benefits to consumers in the long term (**MRP**).

f) It would signal to potential investors that the Authority is committed to long-term, predictable market evolution (**MRP**).

g) Such transition options reduce perceived regulatory uncertainty and provide for the market to adapt to changes over a defined period (**Contact**).

h) It will align with the Authority's FTR proposal in terms of the treatment of rentals (**Contact**).

i) It removes a significant financial barrier to new generation opportunities in the South Island, while avoiding price shock to the end consumers. We agree with TPAG's analysis that end consumers could be financially penalised in the short term, however we wish to point out that this will be offset by a greater benefit of lower wholesale prices due to increased generation capacity (**Mainpower**).

7.4.28 Those submitters against the postage stamp transition note:

a) Under any number of credible alternative scenarios, net price rises to end-use consumers will be much higher than 1%. The transition arrangement only guarantees a transfer of costs from the South Island generators to end consumers and provides very uncertain potential benefit to consumers (**Fonterra**).

b) A slight majority of the TPAG conclude that a postage stamp transition is likely to create an efficiency gain, but does not involve immediate wealth transfers. It will provide efficiency gains with the least likelihood of dis-benefits to consumers (**RTANZ**) .

c) TPAG's own analysis shows that wealth transfers are immediate under any postage stamp transition option. Figure 11 of Appendix D illustrates that consumers will not receive any benefit before 2024 (**RTANZ**).

TPAG response to submitter views on the assessment of postage stamp transition

7.5 Submitter views on the assessment summary

7.5.1 This part of the summary sets out submitter views on two aspects of the assessment summary: whether there is a clear efficiency gain that justifies change and the comparison of the alternatives.

Is change justified? (CAP 2)

Relevant question

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

7.5.3 There is significant overlap between responses to this part of the consultation paper and submitter views on potential efficiency gains 7.1.3. Those that consider that there was evidence of an efficiency gain generally[5] support the majority view that there is a clear efficiency gain to justify change and those that do not agree there was evidence of an efficiency gain agree with the minority view.

7.5.4 Contact, Meridian, MRP, NZWEA, Transpower, TrustPower and Vestas support the majority view. Fonterra, MEUG (and NZIER), Norske Skog, NZ Steel, NZRC, Pan Pac, RTANZ, Vector respond to the question and support the minority view. DEUN, ENA, Genesis, Greypower also support the minority view.

Assessment of alternatives (CAP 3)

Relevant question

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

7.5.6 Contact, Meridian, MRP, NZWEA, Vestas agree with the summary of the alternative options, and the selection of the postage stamp transition as the preferred option. Transpower and TrustPower also agree although gave qualified responses.

7.5.7 'We would qualify the majority conclusion by noting that the incremental generation investment efficiency gain is less certain to be secured than the other efficiency gains, but, on balance, we support the majority conclusion in support of the postage stamp transition option as marginally superior to the per MWh allocation option', **Transpower**.

7.5.8 'While TrustPower's preference would be for an immediate shift to postage-stamping (i.e. without the transition), it appreciates (and agrees with) the need to soften the blow to loads' **TrustPower**.

7.5.9 Fonterra, MEUG (including NZIER in its report to MEUG), Norske Skog, RTANZ, Pan Pac, NZRC, and Vector disagree with the summary. NZ Steel considers that the summary reflected the majority view, but disagrees with the majority view. Other submitters, whilst not directly answering this question disagree with the majority view (DEUN, Greypower, Genesis).

7.5.10 The comments from submitters regarding the analysis of possible efficiency gains and assessment of the options are generally reported in earlier sections of the summary. Some additional comments from submitters are summarised here where they directly comment on the conclusions and summary of the assessment of the alternatives.

7.5.11 Other comments are grouped as follows:

a) referring to the Code amendment principles, statutory objective or long term benefit of consumers; and

b) referring to the analysis underpinning the comparison of the options.

Comments referring to the CAPs, statutory objective or 'long term benefit of consumers'

a) CAP 3 focuses on quantitative assessment and particularly cost benefit analyses. The modelling performed by the TPAG Secretariat is facing significant questioning and has not been subject to independent audit and review (**RTANZ**).

[5] Fonterra is an exception as it answered Q5 closely and has distinguished between evidence to consider further and evidence of a clear efficiency gain.

b) It is not clear that there is a clear long term benefit for consumers which is a requirement of the Statutory Objective (**RTANZ**, **Carter Holt Harvey**, **NZ Steel**). According to RTANZ, the TPAG analysis is clearly equivocal about the probability of long-term benefits to consumers. If these TPAG assumptions do not hold) then consumers will see little or no benefit (RTANZ).

c) The effect on different consumers will potentially be vastly different, disadvantaging those with large fixed loads unable to avoid the RCPD as well as retail customers to whom distributors will pass the cost on (**NZ Steel**).

d) In Carter Holt Harvey's view, the comment on Page 5 of the discussion paper paragraph 35 "….it will provide efficiency gains with the least likelihood of dis-benefits to consumers" provides a clear indication that the TPAG considers that efficiency benefits, if any, are more likely to flow to the supply side of the electricity market than the consumer (**Carter Holt Harvey**).

e) The TPAG paper suggests the majority-supported postage stamp transition option would leave customers worse off (**Vector**).

f) More work is needs to be done in order to demonstrate that a change in HVDC pricing would be to the long-term benefit of consumers (**Vector**).

g) If the proposals are to the long-term benefit of consumers, rather than serving the interests of generators, we would expect to see this reflected in wide-spread consumer support and endorsement of the proposals (**ENA**). RTANZ argues similarly that if the proposed changes really were to the long-term benefit of consumers wouldn't it be expected that at least some of these groups and their members would support them? The work of the TPAG and the slight majority view simply does not allow the Authority to have any confidence that the Code amendments proposed in the paper for the allocation of HVDC costs will be for the long-term benefit of consumers (**RTANZ**).

h) The risks are too great for consumers (**ENA**). A half cent per kWh is anything but trivial for an increasing number of people who are struggling today to pay their power bills.

i) If there are benefits to consumers they will not become apparent for more than ten years (**DEUN**).

Analysis underpinning the comparison of the options

a) **NZIER's** report (Table 5) summarises NZIER's assessment of the summary of costs and benefits. This table reflects NZIER's views of the unintended efficiency impacts and other differences from the views set out in the Discussion Paper. NZIER also submits that summing upper boundaries (as the Discussion Paper did) is not statistically significant.)

b) The 'incentive-free allocation to SI generators' was excluded from the TPAG Table 27 summary comparison of options without an appropriate justification (**MEUG**).

c) In RTANZ's view, TPAG has conflated two separate issues concerning the allocation of costs and the structure of the charge and used this conflation to support the argument that postage stamp is a better allocation. The alleged inefficiencies arising from the HAMI structure have nothing to do with the allocation of costs to SI generators, but are to do with the structure of the charges (**RTANZ**).

d) The analysis has not considered 'normal commercial practice' (**Pan Pac**).

e) Certainly the rules should accommodate and encourage the full use of the available resources. Any hindrance to free operation should be removed (**Pan Pac**).

f) In Contact's opinion, the analysis produced by the TPAG satisfies the CAP3 requirement in relation to the quantitative assessment of options that could lead to Code changes. The conservative approach to the estimation of these net benefits should provide more certainty as to the likelihood of these net benefits being realised (**Contact**).

TPAG response to submitter views on the comparison of the options

"Comments referring to the CAPs, statutory objective or 'long term benefit of consumers'"

7.5.11 (c): Is this comment valid?

7.5.11 (e): Is this comment valid?

7.5.11 (g): Does the lack of consumer support raise questions about the suggestion that the proposals are to the long-term benefit of consumers?

7.5.11 "***analysis underpinning the comparison of options***": Do you consider that the comments (a), (b), and (c) are valid? Should TPAG amend any aspect of comparative analysis?

7.6 Different variants of postage stamping

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

7.6.2 No submitters suggest alternative postage stamping options that have not already been considered or mentioned earlier in this summary.

7.7 Transition options

Relevant question

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

7.7.2 Contact, Meridian, MRP, Transpower, TrustPower agree that the proposed transition option is appropriate.

7.7.3 MEUG, Norske Skog, NZRC, disagree that the transition option is appropriate as they considered that there is not a case established for postage stamping the HVDC. General comments on the postage stamp transition option are given in section 7.4, comments summarised in this section concern the details of a possible transition option.

7.7.4 Submitters make the following comments about the transition option settings:

a) The setting of the transition is a ‘lever’ that can be used to evolve the market to a better long term outcome. If the net benefits to consumers are held to be too uncertain then, rather than reverting to a pricing methodology based on flawed principles, extra certainty can be given to consumers by using either a higher initial price for existing SI generators or a longer transition to make it more likely to lower costs to consumers overall (**MRP**).

b) The option involves an expected net price affect of zero, would mean consumers would be taking on risk for a zero expected return (**Vector**). In Vector’s view, TPAG presented three alternatives which better serve the long-term interests of consumers:

   i) Transition to postage stamp with an initial charge to existing South Island generators of $30kW/year and a transition length of 15 years (option 7);

   ii) Transition to postage stamp with an initial charge to existing South Island generators of $45kW/year and a transition length of 10 years (option 9); and

   iii) Transition to postage stamp with an initial charge to existing South Island generators of $45kW/year and a transition length of 15 years (option 10).

c) Another transition option the Authority could consider would be to delay the decision on (or implementation of) postage stamp pricing of the HVDC link for 10 years (**Vector**).

d) The $30/kW charge is too low. It should reflect the actual nominated HVDC charge as calculated by Transpower, and we expect this to be in the region of at least $40 -45/kW, if not more, once Pole 3 is fully included (**NZ Steel**).

e) Additionally, the transition period should certainly be no less than 25 years, to enable existing industrial consumers to at least derive the expected use and benefits from their investments. A period of this order or even longer will also enable existing generation to continue to be operated on the basis of the same economic models as those applying when the investment in it was made (**NZ Steel**).

f) TPAG should consider aligning the transition to the merit order stack they have developed. It appears that the earliest SI generation would be brought forward in the merit order is to approx five years. We think that the transition should not commence until this time and align as closely as possible with the ‘benefit’ that would be realised from reduced whole sale energy costs (**Fonterra**).

g) **Contact** considered the treatment of the rentals as part of any transition saying it would support HVDC rentals being treated in a similar fashion to HVDC costs i.e. if costs are postage stamped, rentals should be allocated in a similar way. They could be transitioned pro-rata on the same basis as the HVDC charge is transitioned, over the ten year period.

TPAG response to submitter views on the transition options 7.7.4 (b) to (g): Do you consider that TPAG should evaluate other transition options?

7.8 Submitters' other HVDC issues

7.8.1 Submitters raise a series of other issues which are noted here.

How the HVDC may have been taken into account at the time of corporatisation

7.8.2 **Norske Skog**: We also wish to point out that at the time South Island generators acquired their assets they either received a discount on the purchase or, in the case of State Owned Enterprises, their balance sheets were adjusted – in both cases to reflect paying HVDC costs in perpetuity. Thus we do not see what grounds South Island generators have to complain about continuing to be allocated costs for the HVDC. If South Island generators were relieved of the HVDC costs, they would receive a windfall.

The treatment of pole 3

7.8.3 **Norske Skog**: We are aware that some argue that Pole 3 should not be treated in the same way as the existing HVDC assets. We note that Pole 3 is not a new HVDC asset, but rather a replacement control system – in other words Pole 3 is simply a maintenance project and we see no reason for it to be treated any differently from the other HVDC assets.

Transpower's economic value account

7.8.4 **Orion**: We are also concerned with the treatment of Transpower's economic value account, which for the year ending June 2009 had an HVDC customer debit balance of $102.8m. This issue does not appear to have been addressed in the paper, but clearly this debit would need to be recovered by Transpower from the existing HVDC customers.

Signalling any changes

7.8.5 **Powerco**: An increase of the distribution element of electricity bills of this magnitude has the potential to cause damage to the reputation of distribution companies as it is not always possible to convey to consumers the detailed origin of the increase. If the proposal is to be implemented we would welcome efforts by the EA to publicise the change and to ensure that retailers explain the basis of the increase in their communications with consumers.

Perceived consensus amongst participants

7.8.6 **Genesis**: It notes that at the TPAG briefing it was mentioned that the Authority was prompted to form TPAG due to representations that there was a new consensus within the market regarding the HVDC charge Genesis Energy formally notes it was never party to any such consensus or understanding. Such a consensus would imply it was complicit in an understanding amongst suppliers aimed at shifting costs to our customers.

The need to review the effectiveness of decisions

7.8.7 **BusinessNZ**: In light of the high degree of assumption-dependency and potential financial impact associated with this issue, BusinessNZ considers that if the decision is to proceed with the majority option, it is beholden on the TPAG to suggest to the Electricity Authority ways in which it could monitor progress against the assumptions on which the decision is based. **Fonterra** argued similarly that the Authority should monitor the avoided energy costs, but noted that it did not believe this can be done.

The Availability of TPAG modelling

7.8.8 We appreciate the EA making available (upon request) the spreadsheet that was used to justify an efficiency gain. In our view it would have been better regulatory practice for the TPAG to publish the spreadsheet at the same time as the discussion paper, since it is so critical to the TPAG report. (**Norske Skog**).

HVDC rentals

7.8.9 The HVDC rental rightly belongs to the users of electricity and should be reimbursed to electricity users (**Pan Pac**).

Changes in the context of other possible price increases

7.8.10 This impact of the changes is proposed to be mitigated by a prolonged “price holiday” - a 10-year transition period towards the full impact. Other drivers of price increases are in the pipeline, especially scarcity pricing. Each of these will be “consulted on” in the same way as transmission pricing. The cumulative impact of a succession of industry decisions on electricity pricing must be recognised as an onerous burden on domestic consumers (**DEUN**).

TPAG response to submitters views on other HVDC issues

7.8.2: Is this comment about windfall gains to SI generators valid and is it relevant to TPAG?

7.8.3: Is there any reason to treat Pole 3 differently?

7.8.4: Is the debit in the Transpower economic value account of $102.8m a relevant consideration for TPAG?

7.9 General comments on the size of price increases or wealth transfers

7.9.1 Submitters present the following views on the size and impacts of price increases or wealth transfers.

a) We understand that the impact of the option under consideration will result following commissioning of Pole 3 in an increased cost for the consumer that will amount to approximately $23/Kw peak pa which in Carter Holt Harvey’s case will result in increased annual charges of approximately $1.7M pa. (**Carter Holt Harvey**)

b) The quantified benefits of moving from a more efficient charging approach ($/MWh injected in the South Island) to shifting the HVDC charge on to consumers are estimated to be between $7-$39 million net present value ("NPV") over thirty years. By way of contrast, we estimate that the NPV of increased charges to consumers of a changed incidence of HVDC charges could be up to $1.2 billion over 30 years, and even under a transition arrangement, consumers would ultimately become liable for more than $100 million in HVDC charges per annum (**ENA**).

c) Based on this year's pricing, Powerco would have had to increase prices by a further 4.5% to recover the additional transmission charges (**Powerco**).

d) Changing the current allocation method to a postage stamp basis will result in a substantial increase in NZRC's charges for transmission. As a major user of electricity such a change would increase NZRC's costs for transmission by approximately 30% (or ~ $700,000 per annum) **(NZRC).**

e) Under an immediate switch to postage stamp (option 1) consumers would pay an extra $1.25 billion in transmission charges over the next 10 years but would not expect any material benefit during this time. Even under the TPAG majority's preferred postage stamp transition (option 6) consumers would pay an additional $713 million in transmission charges over the next 10 years, without any material benefit. In NPV terms this translates to a tax on consumers of $1.23 billion and $831 million, respectively (**Vector**).

f) This would translates to an increase in transmission charges for consumers, on average, of about $65 per customer per annum for postage stamp or $16.60 per customer per annum increasing to $51.90 over 10 years[6] for the TPAG majority's preferred postage stamp transition (option 6) (**Vector**).

g) Postage stamp pricing would increase the cost of power to all consumers by about 0.35c/kWh, an immediate and certain price increase. As a result, South Island generators would save around $150 million of their costs annually, at the expense of all consumers (**DEUN**).

h) A further retail margin would be added wholesale price increase of 0.35c/kWh, taking the increase up to perhaps a half cent (**DEUN**).

6 These calculations assume (i) postage stamp charges for the HVDC would be net of HVDC rentals, a discount rate of 8% and constant (nominal terms) transmission charges between 2035 and 2042. The calculations are based on an adaption of a spreadsheet prepared by John Culy available at:
http://www.ea.govt.nz/our-work/consultations/advisory-group/transmission-pricing/. Refer to Figure 3 for a comparison of the impact of HVDC rentals being passed on to consumers or not on the HVDC they would face under postage stamp pricing of the HVDC link.

TPAG response to submitter comments on the size of price increases or wealth transfers 7.9.1 Should TPAG respond to these estimates?

8 Assessing options for deeper or shallower connection

8.1 Requirement for coordination with the Commerce Commission

Relevant question

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

8.1.2 Most submitters who responded to this question consider that further analysis would require coordination with the Commerce Commission: ENA, Contact, Fonterra, Meridian, MRP, NZ Steel, RTANZ, Transpower, TrustPower, Vector.

8.1.3 **Pan Pac** submits that there was no need to change the connection definitions. **MEUG** submitted that coordination is 'desirable but not necessary'. 'Both regulators have their own statutory objectives, various statutory deadlines they must achieve (e.g. Commerce Commission has statutory deadlines with respect to the capital expenditure Input Methodology applicable to Transpower) and a MOU agreed on managing boundary issues. Both regulators should work to meet their own statutory requirements first, with opportunities for coordination taken as they arise.

8.1.4 **MEUG** is 'disappointed a more thorough analysis beyond that already undertaken by the EC was not made.' **Fonterra** makes a similar point saying it is disappointed that the TPAG work did not reach a recommendation with a lot of emphasis on the HVDC charge work.

8.1.5 **ENA** submits that there are a number of issues that need to be understood in progressing the analysis through coordination with the Commerce Commission and ideally any work on pricing of connection assets should inform improvements as to how transmission services are handled under price/quality regulation.

i) the relevant shortcomings in the current price/quality regulation arrangements applying to EDBs and the incentive effects on EDBs that arise from these arrangements; and

ii) the transmission alternatives regime emerging in the Commerce Commission's Input Methodology process.

TPAG response to submitter views on the requirement for coordination with the Commerce Commission 8.1.3: What is your view on MEUG's assertion that coordination between the Authority and the Commerce Commission is desirable but not necessary?

8.2 Possible efficiency gains from deeper allocation of costs

Relevant question

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

8.2.2 **Meridian**, **Contact** considers that the efficiency gains were likely to be at the low end, or be uncertain. **Transpower** considers that there is no evidence that flow tracing or 'but-for' would produce any net national benefit, and asserts they could lead to a net national cost. Transpower notes that the analysis of possible efficiency gains takes no account of the additional costs associated with the increased disputes over the interpretation of the TPM and the prices. On the other hand, Fonterra believes that it is reasonably likely that these gains can be realised and **RTANZ** submits that such gains are possible and even greater gains could be made by extending deep allocation to include generation assets. RTANZ claims, by way of an example, that one of the lower SI grid upgrade plans is primarily to facilitate generation investment, however, the generators will pay none of the costs.

8.2.3 **MEUG** considers that the likelihood of the gains should be 'assessed empirically' and TPAG should have done this. TrustPower considers more analysis is required to determine whether the gains can be realised, along with analysis of the benefits of a shallower connection.

8.2.4 **Powerco** suggests caution in assumptions around demand side management (DSM) scenarios, it is not currently possible to trade demand management in the market but if this is opened up there will be far greater material incentives for participants to enter this market, which will impact forecasts.

8.2.5 **MRP** considers that there are only small efficiency gains available from deeper allocation at the fringes of the grid through the allocation of costs. The efficiency gains from optimising the capacity of interconnection would yield larger gains. For example, the NPV of congestion settlement surpluses with deep allocation is much larger than the NPV estimates without it. According to MRP, paralleling smaller lines into the core North Island 220kV grid is an example where local benefit is constraining overall grid capacity. Yet a small 110kV circuits run in parallel with large 220kV lines is likely to show the usage characteristics of an interconnector, and the only advantage would be to offer n-1 security for customers on the 110kV line. Most customers on the overall grid will actually suffer detriment through reduced grid capacity and thus increased congestion.

8.2.6 **MRP** notes that he problem with deeper connection is that it applies user-pays as a proxy for determining beneficiaries which is a significant underlying cause of the HVDC charging problems. The issues around the fringes of the grid are fundamentally about investment and disinvestment. There is little practical point in trying to address these issues through transmission pricing, particularly as the allocation of deep connection costs does not imply commensurate rights to be actively involved in the decision making framework.

TPAG response to submitter views on the possible efficiency gains from deeper allocation of costs

8.2.3: Should TPAG undertake further analysis on possible efficiency gains?

8.2.4: Is Powerco's view valid? 8.2.5: Is MRP's view valid, and should TPAG consider it in its analysis?

8.3 The range of options for deeper of shallower connection

Relevant question

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

8.3.2 Contact, Fonterra, Meridian, TrustPower and Transpower submitted that they agree with the range of options, or that the range of options is 'satisfactory', although some of these submitters raised issues with the options identified. These issues are summarised in section 8.4.

8.3.3 Both RTANZ and MEUG do not agree, commenting that the deeper or shallower cost allocation has not received adequate consideration by TPAG giving no confidence that the range of options is satisfactory.

8.3.4 MRP does not agree with the options as it believes all of the options would be problematic.

TPAG response to submitter views on the range of options for deeper of shallower connection

8.4 Assessment of the deeper or shallower allocation of costs options

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

8.4.2 Submitters views on the assessment of options are grouped as follows:

a) Shallower connection.

b) General comments on deeper allocations.

c) But-for.

d) Flow tracing.

e) Comments on the application of the efficiency considerations to deeper or shallower allocation of costs.

Shallower connection

a) A more practical definition of connection including only the substation assets and excluding dedicated generation spur lines would remove any unintended perverse incentives and avoid any chance of major change due to grid reconfiguration or development in the future (**Contact**).

b) A shallow grid (i.e. treating existing load spurs as interconnection assets) would potentially provide for lower cost generation connection going forward. Other "interconnected" stakeholders should encourage this as it promotes generation in remote areas, ultimately lessens demand on the interconnected grid, and can provide necessary voltage support where it is most needed (**Contact**).

c) A shallower connection charge where Transpower's costs are moved from the connection charge into the interconnection charge will reward embedded generators more through higher avoided transmission payments (**WEL Networks**).

General comments on deeper allocations

a) Both flow tracing and but-for have received scant attention and should be explored more fully **(MEUG**, **RTANZ)**.

b) A deeper allocation of costs would more closely align the TPM to beneficiary-pays, resulting in generators contributing to AV and HVDC grid costs. However, application of beneficiary-pays gets exponentially more complicated the deeper it is applied to the transmission grid and the more potential beneficiaries there are **(Vector)**.

c) A price incentive alone will not create the degree of reliability needed to make a peaking station an effective transmission alternative. Only the detailed transmission alternatives regime, supported by contractual requirements, can do this (**Transpower**).

d) Increased complexity would also increase the scope for customers to find ways to shift costs onto others. Such activity represents a net cost to the nation as a whole (**Transpower**).

e) Both But-for and flow tracing could lead to increased disputes (**Contact, Meridian, Transpower**). Transpower estimates the cost of increased disputes could easily amount to $2m p.a. for the industry as a whole, an NPV of c.$28m at a 7 per cent discount rate. Disputes Transpower refers to a quotation from the 2007 Castalia paper on the "but for" method prepared for Transpower:

> 'Based on evidence in PJM, adopting an approach that assigns costs to those who benefit can be fraught with problems. PJM has spent years and tens of millions of dollars litigating the method used to calculate benefits for reliability and system network upgrades. There can be little doubt the many conflicts will arise using this type of pricing approach since different methodologies to determine benefits can cause wide swings in the allocation of costs.'

But-for

a) "But for" allocation rules would be bound to be complex and open to dispute (**Transpower**)

Flow-tracing

b) Flow tracing is complex and would change year to year (**Contact**).

c) Flow tracing would add an additional asset category ("allocated interconnection") and hence an additional asset boundary between allocated interconnection and general interconnection. This boundary would also be variable depending on modelled energy flows.

The additional asset boundary and the need for definitions of the asset allocations at the boundary nodes would increase the scope for disputes (**Transpower**).

d) The price signal may not have any meaningful effect on consumption or investment decision making because:

   i) it would be meaningful only for distribution companies and direct connects. By contrast, the transmission alternatives process engages a much wider range of stakeholders; and

   ii) once passed through to end consumers the price signal from flow tracing would be very weak (e.g. a 20 per cent increase in Vector's transmission charges would translate to a roughly 2 per cent increase in end use consumers' total electricity charges (**Transpower**).

e) No evidence has been provided to show that a flow tracing based charge would accurately reflect the long run marginal cost of new grid investment (**Transpower**).

TPAG response to submitter views on the assessment of deeper or shallower allocation of costs 8.4.2 ***Shallower connection*** (c): Is this view valid and should TPAG take it into account? 8.4.2 ***General comments on deeper allocations*** (a): Should TPAG undertake further work on flow tracing and but-for approaches? 8.4.2 ***General comments on deeper allocations*** (e): What is your view on the suggestion that increased costs arising from disputes under flow tracing and but-for could be relatively high?

Comments on the application of the efficiency considerations to deeper or shallower allocation of costs

Efficiency consideration 1: beneficiary pays

a) **MRP** considers that none of the options have greater merit than the status quo. Flow tracing incorporates usage volume as a proxy for assessing beneficiaries. What but-for achieves is that by paying for the marginal transmission investment a remote generator has to be able to sufficiently undercut the price of a local generation to pay for the transmission investment. This appears to be a form of enhanced locational pricing rather than a deep connection definition.

b) It may not be reasonable to assume that benefit is proportional to allocated flow shares but that, also, if, on most occasions, a customer would observe little change to its service, including price, if an interconnected asset that it was modelled as "using" were not there, the asset could not be said to be benefiting the customer to any meaningful extent. Different customers may also obtain different benefits, or different rates of benefit from the same asset (**Transpower**).

c) With respect to the 'but for' approach, the lumpiness of efficient grid investment is always going to present a problem in relation to the application of the beneficiary pays principle. This is particularly true for a small scale grid, such as New Zealand's grid. The 'but for' principle may be able to identify one or more large beneficiaries of an investment at the time it is made, or the investment proposal is considered. However, other users are likely to appear later to take advantage of excess capacity produced by the investment. Are these customers to be permitted to use the now sunk assets at no additional cost, or are the charges to be shared? If the latter approach is applied, the interpretation of the sharing rules can easily lead to costly disputes. Also, as noted above, on the interconnected grid, it can be difficult to identify to what degree an individual customer actually benefits from particular assets (**Transpower**).

Efficiency consideration 2: Locational signalling

a) Enhanced locational pricing was identified by TPAG as not having merit, so the 'but for' concept should also be dismissed. Other enhanced locational pricing options are more likely to deliver net benefits than 'but for'. Retaining 'but for' necessitates that all enhanced locational pricing options would have to be reconsidered (**MRP**).

b) As with other enhanced locational pricing systems there is the potential for disbenefits. 'But for' only works when the transmission investment is genuinely marginal. If significant economies of scale are part of the decision to invest then allocating these surplus costs to the marginal generator is also inefficient (**MRP**).

Efficiency consideration 3: unintended efficiency impacts

a) With respect to the 'but for' method, there would be incentives to time investments strategically to avoid being 'caught' by 'but for' charges, and also to dispute the allocation of charges. These incentives create unintended economic costs (**Transpower**).

Efficiency consideration 4: Competitive neutrality

8.4.3 No comments

Efficiency consideration 5: Implementation and operating costs

a) The costs of disputes related to the flow tracing method would be greater than that estimated by TPAG. Something like $2m p.a. or NPV $14m would be more likely. Transpower is probably more aware of this risk than other industry participants because of past experience of disputes over pricing. One of the big advantages of the current TPM is that its clear definitions and relative simplicity have greatly reduced the incidence of disputes (**Transpower**).

b) With respect to the 'but for' method, TPAG's estimate of the costs of administering the allocations and resolving disputes is closer to being correct, but is probably still understated (**Transpower**).

Efficiency consideration 6: Good regulatory practice

c) The flow tracing and 'but for' methods would substantially increase the scope for disputes and this would be likely to undermine the durability of both methods. The scope for gaming these methods is also inimical to the achievement of consistency over time (**Transpower**).

TPAG response to submitter views on the application of the efficiency considerations to deeper or shallower allocation of costs 8.4.2 ***Efficiency consideration 2***: What is your view on the MRP suggestion that but-for options should be dismissed? 8.4.2 ***Efficiency consideration 3***: What is your view on the Transpower suggestion that but-for options could create unintended economic costs? 8.4.2 ***Efficiency consideration 5***: What is your view on the Transpower suggestion that the cost of disputes under flow tracing would be greater than estimated by TPAG?

8.5 Justification to progress further analysis of connection options or a deeper allocation of costs to specific customers

Relevant question

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

8.5.2 Fonterra, MEUG, RTANZ, Powerco and TrustPower submit that the Authority should progress further analysis before decisions are made. They give the following reasons:

a) The TPAG work has not advanced the thinking on the HVAC TPM much compared to the Electricity Commission. The Authority cannot rely on the TPAG analysis and will be required to undertake further work ahead of deciding if there is an opportunity of coordinating with the Commerce Commission (**MEUG**).

b) If the Authority is serious about applying a beneficiary pays approach to transmission pricing then this must be done (**RTANZ**).

c) Any change other than shallower connection will have high implementation costs so careful analysis is needed (**TrustPower**).

8.5.3 **Contact** says it is 'hesitant' about the value of further analysis. **Meridian** is keen to understand how transmission alternatives will work in practice before work on alternative connection pricing options.

8.5.4 **Transpower** believes that the Authority should agree that TPAG has undertaken sufficient justification for concluding that no further analysis should be undertaken. Transpower argues that he RCPD method and the transmission alternatives regime are likely to achieve the same outcomes.

8.5.5 **Genesis Energy** considers that there is not evidence that there would be a clear and material efficiency gain from changing to a deeper or shallower definition of connection assets and given that any change would shift the incidence of costs and would inevitably create a new set of problems supports retention of the status quo connection depth.

8.5.6 **MRP** considers that: 'Pursuing deeper connection options on existing grid configurations would achieve only a small part of the available benefits. Any proposed application of a beneficiary pays model needs to use the optimal configuration (in terms of maximising net benefit) of the current grid as the counterfactual.

TPAG response to submitters views on where to progress further analysis 8.5.2, 8.5.4: Should the Authority progress further work on deeper allocation of costs?

8.6 Other issue related to deeper or shallower allocation of costs

8.6.1 DEUN characterised the second issue (deeper versus shallower) dealt with by TPAG as whether generators should pay for parts of the national grid that are used mainly by them, but also available for other users. The direct impact on domestic consumers appears minimal, but there may be issues for small-scale 'distributed energy' providers, which may become increasing important as large-scale electricity supply runs out, and environmental factors including climate change constrain the otherwise cheaper electricity options.

TPAG response 8.6.1: What is your view on whether deeper versus shallower connection charges creates issues for small-scale 'distributed energy' providers and for environmental factors?

9 Assessing options for static reactive compensation

9.1 This is in a separate document

10 Conclusion and draft Guidelines

10.1 Relevant question

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

10.1.2 Transpower, MRP and Vector have alternative drafting suggestions for some of the guidelines which are set out below.

Table 2 Suggested alternative drafting of Guidelines

Guideline #	Suggestion	Submitter	Rationale
2	Transpower is to provide an update to Schedule 12.4 to Part 12 of the of the Electricity Industry participation Code 2010, which may be accompanied by an explanatory "supplementary information" document if Transpower considers this appropriate.	Transpower	"Pricing for Grid Connection Services" mentioned in the current Guidelines is an historical document that has now been superseded by the methodology set out in Schedule 12.4 to Part 12 of the Electricity Industry Participation Code 2010.
6	No changes to connection definitions are proposed at this time	MRP	This makes it clear that Transpower should neither consider nor consult on these aspects.
13	No changes to the prudent discount regime are proposed at this time	MRP	This makes it clear that Transpower should neither consider nor consult on these aspects.

10.1.3 **Vector** suggests the drafting of the Guidelines referring to the SRC changes does not refer to individual points of service, but enables the aggregation of power factors across a number of points of connection in a particular region.

10.1.4 **Transpower** comments in its submission on the requirement for Transpower to review the basis for the interconnection charge.

10.1.5 Transpower understands the reasons for this proposed review are that:

i) the recommended change to a postage stamp allocation for the HVDC charge would slightly increase the strength of the signal that the RCPD method provides to encourage load flattening, given the larger proportion of Transpower's revenue that would be allocated to interconnection, and this may or may not be appropriate;

ii) the use of n=12 in the UNI and USI regions, which was intended to provide a slightly stronger load control signal because of the forecast need for substantial new investment in those regions, may no longer be required, because the major investments needed to meet forecast regional load growth are now already committed and in train.

10.1.6 Transpower notes that such a review will consume additional time and resources and may not be consistent the achievement of the Authority's objective of amending the TPM in time for the changes to be applied to the calculation of charges for the 2013/14 pricing year. Transpower suggests that, if the Authority decides to include this guideline, Transpower and the Authority should agree to a limited scope for the review.

TPAG response to submitter suggestions for alternative drafting of Guidelines **Do you support the alternative drafting for the Guidelines?**

11 Other issues concerning TPAG or the Review process

11.1.1 Submitters raised other issues concerning the timeframes for the Review and consultation, the TPAG process, selection of members and advisors and appropriate disclosure of conflicts of interest. The following submitters raised issues:

11.1.2 **MEUG**:

a) has concerns with how TPAG was formed and its relationship to the Authority including consistency with the Authority's own Charter documents for advisory groups. We are also considering how the members and advisors to TPAG were selected and whether an appropriate level of disclosure of conflicts of interest has been made by advisors in particular.

b) is not satisfied that the Authority has provided a satisfactory reason as to why progress is urgently needed to allow implementation of changes to TPM, should that be found desirable, by 1st April 2013.

c) notes the decision by the Authority to decline its request for an extension to the deadline for submissions has cut short our ability to examine all issues in the consultation paper. To that extent this submission focuses on the most important issues identified to date and therefore cannot be taken as our definitive view on all issues.

11.1.3 MEUG stated in its submission that it is likely to wish to seek a discussion on these and other matters directly with the Authority Board in the very near future.

11.1.4 **Norske Skog** notes that

a) Prior to commenting on the process employed by the Electricity Authority, Norske Skog Tasman had representation on the CEO Forum Transmission Pricing Technical Group, throughout 2009. and as of the end of 2010 Norske Skog Tasman had representation on the Electricity Authority's Transmission Pricing Technical Group. Following the Christmas/New Year holiday season, TPTG was replaced by the TPAG, and Norske Skog had no opportunity to be represented. This may not have been a deliberate strategy of the Electricity Authority, but rather a consequence of the rush to form the TPAG. We do not understand the need for the rush. Neither do we understand the frantic progress from then on, with the TPAG meeting regularly even though transmission pricing is not a Section 42 matter and, at the TPAG's own admission, there is no possibility of inefficient investment over the next 5-10 years (D.4.13). If not for this distraction of resources the Electricity Authority could presumably have made much more progress on things that will really bring benefits to consumers such as dispatchable demand and increasing the number of loss tranches in SPD. It is disappointing that the Electricity Authority and TPAG seem to be obsessed with reviewing who pays for the HVDC – which is quite clearly all that this consultation is really about.

b) TPAG's haste has lead to numerous errors of judgement and analysis.

c) It would have provided more feedback to the TPAG, but unfortunately its request for extension of time was declined.

d) It suggests that the TPAG should slow down, conduct a thorough analysis and consult properly before making any recommendations to the Authority.

11.1.5 **NZ Steel** wishes to advise that it has some concerns around potential conflicts of interest, TPAG composition, the process around TPAG's establishment and the EA's decision-making.

11.1.6 **Pan Pac** is concerned with the:

a) frequent use of majority and minority view. It might be more helpful if this was reported by the sectors represented in the TPAG. It must be noted the underrepresentation of electricity users, the ultimate providers of money to the electricity industry. Unfortunately users are much dispersed and electricity is not there main focus, which is in direct contrast with only a few generators' and transmission companies whose whole business is the electricity industry. Near all of the generators (and retailers) and many lines co's being directly represented. A result is poor representation of users and an unbalanced representation of views even when people try to be unbiased.

b) asymmetrical representation of electricity industry participants on TPAG. It is a huge issue for reviews of the electricity industry with the under resourced, small scale fragmented with few user's representation. Users have 4 out of the 18 members of TPAG excluding the chairman. The balances of members are suppliers which results in a highly unbalanced membership.

11.1.7 **DEUN** commends the Authority for its practice of holding briefing sessions for all stakeholders. This allows each stakeholder to hear argument from other perspectives – and gives the opportunity for genuine engagement on the issues. Carl Hansen, the CEO of the Electricity Authority said at the transmission pricing briefing that that Advisory Groups now have a more significant decision-making role than they did under the previous Electricity Commission. Hence, he said, it is very important that they have "balanced membership".

11.1.8 DEUN considers the current membership is not balanced. The ten members of the Group include two major electricity users (Comalco and Fonterra) and five generators. Domestic consumers are not represented at all.

11.1.9 Challenged on this membership by DEUN, Hansen claimed that it does not matter because all members are also domestic consumers, as is each member of the Authority's Board. This claim is fatuous - it holds domestic consumers in contempt. None of the current members are there to represent domestic consumers, and their presence does not constitute domestic consumer representation. Nor does it address DEUN's particular concerns about older consumers, consumers on fixed incomes, disabled consumers, and other types of vulnerable consumers. These groups face difficulties and frustrations that we believe are completely outside the experience of the members of the Advisory Group and Board.

11.1.10 Domestic consumers must have their own representatives, as the interests of consumers are held to be of paramount concern. . "Long term benefit to consumers" needs to be defined by consumers themselves, not by a mechanistic economic analysis.

11.1.11 The issue of HVDC pricing clearly demonstrates how the lack of domestic consumer representation results in decisions which disadvantage this group, and in this case, all consumers. The accumulation of many such decisions is leading to completely unacceptable price rises.

11.1.12 DEUN considers that this, and indeed all consultations, should consider a wider spectrum of impacts and concerns than pure economic efficiency.

11.1.13 **Transpower** strongly recommends that part of TPAG's proposal to the Authority's Board should be a recommendation that any new set of transmission pricing guidelines should bring the transmission pricing review to a final close. Transmission pricing has now been under almost constant review since 2004. The time has come to provide some certainty and stability to the industry going forward and to focus on the higher priority parts of the Authority's work programme, which present much greater potential opportunities for meaningful economic benefits.

11.1.14 Transpower will begin the process required to calculate 2012/13 prices in August 2012. Changes to the pricing software and other administrative procedures need to commence at least three months before August (i.e. May) if they are to be in place, tested and auditable in time to be applied during the "pricing round". Hence, on the face of it, the timeline above would make it impossible to meet the Authority's objective of a 1 April 2013 implementation date.

11.1.15 However, it may be possible for Transpower to commence work to implement the TPM changes in tandem with developing the proposed amendments to the methodology if agreement can be reached between Transpower and the Authority that the Authority will not make any substantial amendments to the draft methodology proposed by Transpower (provided the draft methodology gives effect to the pricing guidelines).

11.1.16 Agreement will also need to be reached on the scope of the proposed review of the use of n=12 in the UNI and USI regions. This will need to be quite a limited desktop study if the Authority's implementation objective is to be achieved.

11.1.17 Another option that could be considered would be to stagger the dates on which different elements of the amended TPM come into force. This might be appropriate if the new static reactive power charge requires more time to implement than the changes to the HVDC charging method.

11.1.18 A further complication is that the power factor requirements in the Connection Code can only be amended via a review following the process set out in clauses 12.19 to 12.25 of the Electricity Industry Participation Code 2010 (see clause 12.18 of the Code). As this review should be completed ahead of the implementation of the proposed static reactive power charge, this process requirement is another factor that could delay the implementation of this charge.

11.1.19 Transpower notes that clause 12.94 of the Code requires the Authority to consult with Transpower when determining a date on which the TPM must take effect. We look forward to discussing the above issues with the Authority when it undertakes this consultation.

TPAG response to other submitter views

Note: Non of these have been highlighted as they do not appear to be within the scope of TPAG.