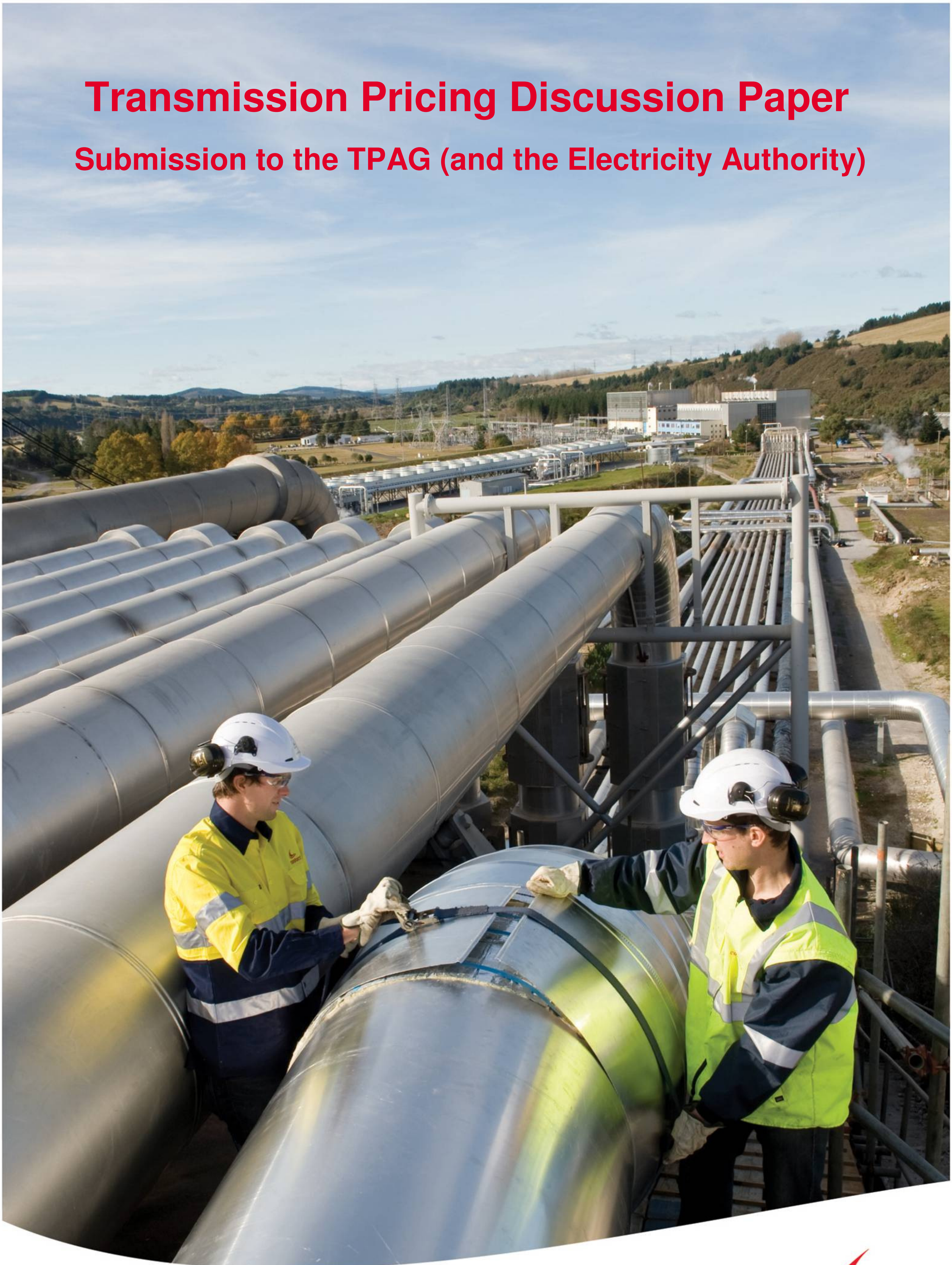
Transmission Pricing Discussion Paper

Submission to the TPAG (and the Electricity Authority)



From Contact Energy Limited

This submission has been prepared by Contact Energy Limited ("Contact") in response to the *Consultation Paper – Transmission pricing discussion paper* (the "consultation paper") issued by the Transmission Pricing Advisory Group ("TPAG") on 7 June 2011 in conjunction with the Electricity Authority ("the Authority").

For any questions relating to our submission, please contact:

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Summary

Contact supports the majority TPAG recommendation on HVDC cost allocation

Contact submits that the TPAG has identified material net benefits that would potentially be obtainable by moving from the existing HVDC cost allocation, to a postage stamp allocation (with transition) to offtake customers.

Contact submits that the TPAG's analysis of the inefficiencies inherent in the current HVDC cost allocation:

- Provides evidence of inefficiencies that are practically observable to market participants;
- Supports similar analysis undertaken by the Electricity Commission;
- Has consistent outcomes over various sensitivity and scenario tests;
- Is conservative, which should mean that net benefits are more likely to be achievable over time (than would otherwise be the case); and
- Produces results that justify consideration of alternative HVDC cost allocation methodologies.

In relation to the alternative cost allocation methodologies considered by the TPAG, Contact believes that the estimated net benefits of each option have been determined in a way that aligns with the statutory objective of the Authority. Based on this analysis, and further to our previous submissions on HVDC cost allocation, Contact supports the TPAG majority's favoured option (postage stamp transition) and believes that this option:

- Appropriately classifies the HVDC as an interconnected transmission asset, with its costs recovered accordingly;
- Has estimated net benefits that are material, exceed those of other options considered, and which are sufficient to justify a change from the status quo methodology;
- Aligns well with the Authority's proposal for managing location price risk (i.e. FTRs); and
- Eliminates the primary concerns identified by opponents to the methodology i.e. wealth transfers.

Contact submits that there are no issues attributed to the views of the TPAG minority that would suggest the estimated net benefits of the TPAG majority's favoured option are not potentially achievable.

<u>Contact supports a pragmatic demarcation of connection/interconnection assets</u>

Contact submits that the 'depth' of grid connection should:

- Encourage generation connection on radial load spurs;
- Increase competition in the provision of generation to remote locations; and
- Defer or avoid transmission investment.

Due to the complexities of trying to optimise the degree of connection depth (and hence to try and secure these benefits), Contact submits that the demarcation between connection and interconnection should be determined pragmatically, and hence largely supports the existing demarcation definition.

<u>Contact submits that static reactive compensation be on a $/kVA basis</u>

Contact submits that:

- As investment decisions for assets are made on a kVA rating basis, demand (interconnection) charges for those assets should be charged on a simple $/kVA basis;
- This would incentivise offtake customers to improve power-factors at their source;
- The kVA would be determined at RCPD periods;
- A kVA charge would achieve the same outcome as the kVAr charging approach; and
- This should be applied as a nationwide standard, with a technical minimum of 0.95 lagging being set in regulation.

HVDC cost allocation

Inefficiencies created by the status quo have been quantified by the TPAG, and warrant the consideration of alternatives

Contact supports the TPAG's use of the Authority's Code Amendment Principles ("CAP") in order to ensure that any potential Code change that may result from their investigations aligns with the Authority's statutory objective.

CAP2[1] is particularly important, as it requires that any Code change be supported by a clearly identified efficiency gain or regulatory/market failure. Contact believes that there are, and that the TPAG has shown that there are, material efficiency gains available by moving away from the existing approach to HVDC cost allocation.

Inappropriate classification of HVDC contributes to inefficiency

These potential efficiency gains exist because of the unique, and in Contact's view inappropriate, 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. The efficiency gains simply reinforce that the status quo methodology is not durable over a range of market conditions (or over time); particularly as transmission investment shifted fundamentally from being contract based, to being set by a regulated investment framework.

The inefficiencies are observable in practice, in the market

Practically, inefficiencies inherent in the current cost allocation methodology are observable to Contact and other participants in the market as:

- An impairment to the relative economics of South Island generation projects; and
- A disincentive to invest in, and offer peaking capacity in the South Island.

In terms of the impost on the relative economics of South Island generation, there are many practical examples of South Island investments whose development is hindered by the current

[1] See the Consultation Charter, 20 December 2010, page 4.

HVDC cost allocation methodology. Trustpower recently indicated[2] 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.

In terms of the disincentives for providing peaking capacity in the South Island, Contact has repeatedly indicated that its operational management of peaking capacity from its Clyde and Roxburgh power stations is directly affected by the current HVDC cost allocation methodology. Under certain hydro conditions, Contact could be incentivised to offer up to an additional 50MW of hydro peaking capacity under a non-distortive HVDC cost allocation methodology. 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. This peaking capacity is then necessarily supplied by other, potentially more expensive, North Island generation.

These 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. Even at this high level, it is difficult to see how these inefficiencies, and their consequences, can be in the best interests of consumers over the long-term.

The TPAG has provided analytical support for these observations

The TPAG's analysis provides quantification of the effects of these observable inefficiencies (and others). The TPAG estimate that:

- There is a disincentive for new grid-connected generation in the South Island relative to the North Island which could lead to generation investment inefficiencies of between $14 and $64 million[3].
- The HAMI allocation discourages investment in new grid-connected peaking capacity in the South Island, resulting in the risk of an investment inefficiency of up to $42 million (on an NPV basis); and

[2] http://annualreport.trustpower.co.nz/~/media/Files/Publications/Infratil%20Investor%20Day%20-%20March%20-%20FINAL.ashx
[3] The consultation paper, paragraph 6.2.16

- The HAMI allocation encourages the withholding of grid-connected South Island peaking capacity from the market resulting in the risk of a dispatch inefficiency of up to $10 million (on an NPV basis).

The TPAG's modelling estimates are reasonable and pragmatic

Given the complexity of modelling the efficiency effects from sunk asset cost recovery, the TPAG's modelling is reasonable and pragmatic. The results are also likely to be conservative. While there will always be debate around the suitability of key assumptions underpinning the analysis, Contact believes that the approach taken is useful in that it:

- Provides for sensitivity testing and scenario variation to test key assumptions;
- Makes use of the SOO, an independently derived assessment of broad industry information about potential generation projects; and
- 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.

The consultation paper indicates that the outputs from the sensitivity analysis and scenario testing were relatively consistent. 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.

The use of a conservative approach should help identify net benefits that are more likely to be achievable over time, than would otherwise be the case.

The TPAG analysis aligns with that of the Electricity Commission

As part of its Stage 2 analysis of transmission pricing[4], the Electricity Commission ("the Commission") undertook modelling to estimate any inefficiencies resulting from the status quo HVDC cost allocation methodology. The TPAG's work aligns with the results of the Commission's GEM analysis, identifying inefficiencies at the lower end of the range produced by the Commission[5]. The Commission's preliminary observations from that analysis were that:

- There is a net cost in terms of the impact of incentivising North Island generation options at the expense of (what would otherwise be) more economic South Island options; and

[4] *"Consultation Paper Transmission Pricing Review: Stage 2 Options"*, Prepared by the Electricity Commission, July 2010.
[5] This is likely to reflect the relatively conservative approach taken by TPAG to its modelling.

- The cost of disincentivising South Island generators from investing in new peaking capacity is small but material.[6]

These preliminary views align with the results of the analysis undertaken by the TPAG.

Contact supports the TPAG's conclusion that evidence of the inefficiencies supports the consideration of alternative cost allocations

The TPAG conclude that there are inefficiencies inherent in the status quo HVDC cost allocation methodology that mean other options should at least be considered i.e. there is "sufficient evidence to warrant further analysis of alternatives".

Contact supports this conclusion, and believes that the inefficiencies have been shown to be material. While some are likely to argue that, in terms of the total present value of the cost of generation in the long-run the inefficiencies (in isolation) are relatively small, it was undisputed (in TPAG) that it is prudent to proceed to analyse the various options on an NPV basis to ensure that the total net costs of these options are considered.

The TPAG has identified appropriate options and criteria for further analysis

Options are those considered by industry to be pragmatic

The consultation paper indicates that the TPAG has used information from the stage 2 analyses undertaken by the Commission, submissions on the stage 2 consultation, and feedback from TPAG members in identifying a series of alternative HVDC cost allocation options. Contact supports this approach. Usefully, the options identified by TPAG also rule out those which continue to treat the HVDC as a 'special case'.

Criteria used to assess options should provide for an assessment that is consistent with the Authority's statutory objective

The TPAG has developed criteria for assessing the relative merits of HVDC cost allocation options that recognise the importance of efficiency considerations in the Authority's interpretation of its

[6] *"Consultation Paper Transmission Pricing Review: Stage 2 Options"*, Prepared by the Electricity Commission, July 2010, page 28.

statutory objective (given the overall requirement to act in a way that is for the long-term benefit of consumers). Contact supports this approach, and the expanded efficiency considerations applied[7].

The criteria also provide for qualitative assessment of the relative costs and benefits of the various options, as required by CAP3.[8] The use of the criteria also aligns with the decision to remove the transmission pricing principles[9] from the decision framework.

Contact supports the TPAG's analysis of the relative costs and benefits

HVDC capacity rights

While the HVDC capacity rights option seems potentially useful in that it might help identify those who are willing to pay for rights to HVDC capacity, the complexities associated with creating the process to identify those parties, and with trying to introduce it to the New Zealand market, significantly reduce its value in practical terms. The TPAG has estimated that these complexities could result in implementation costs of between $20 and $40 million[10], which far exceed those of the other options considered (estimated at around $1 to $2 million). The HVDC capacity rights option would also 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 submits that the inability of the TPAG to quantitatively assign benefits to offset these significant costs is likely to reflect the theoretical nature of the benefits (c.f. practical 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.

It may be that the potential benefits of a capacity rights option would be more readily identifiable in an environment where HVDC capacity was constrained, but as the TPAG note[11], this is not likely to be the case for 20 – 30 years (i.e. until additional HVDC capacity is required).

Similarly, 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

[7] See the consultation paper, paragraph 4.3.2.
[8] See the Consultation Charter, 20 December 2010, page 4.
[9] See the consultation paper, paragraph 3.2.2.
[10] See the consultation paper, paragraph 6.4.58.
[11] See the consultation paper, paragraph 6.4.24.

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.

MWh allocation to South Island generators

Contact submits that a MWh allocation to South Island generators would make no difference in terms of the beneficiary pays efficiency principle compared to the status quo. It would also continue to impair the relative economics of South Island generation projects, albeit to a lesser extent than the status quo.

The most material benefit of this option is removing the disincentive to invest in, and operate, South Island peaking capacity, created by the HAMI methodology. While these potential efficiency gains could be material, Contact is concerned that this option is still underpinned by a flawed allocation to South Island generators only, who are one of a number of beneficiaries of the link. Contact believes that other options are likely to produce similar, if not higher, efficiency gains, but remove additional distortions by treating the HVDC like other interconnected transmission assets.

Incentive free allocation to SI generators

Similar to the MWh allocation to South Island generators, the incentive free allocation option won't produce any benefits (compared to the status quo) in terms of ensuring beneficiaries of the HVDC pay for the right to those benefits. It may even be worse (in terms of inefficiencies) than the status quo, in that it will treat existing and new South Island generators differently.

Having an incentive free allocation 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 agrees with the TPAG that the incentive free allocation option is unlikely to be workable[12].

Postage stamping HVDC costs to offtake

Contact submits that the option to postage stamp HVDC costs to offtake customers appropriately treats the HVDC like other interconnected transmission assets. Contact continues to believe that such treatment will better allow consumers to understand the full opportunity cost of their

[12] See the consultation paper, paragraph 6.5.25.

consumption decisions, which can only lead to improvements in investment and operational decisions for those assets.

In terms of identification of beneficiaries, postage stamping recognises the reality that the ultimate beneficiary of the asset is the consumer, so at a high level, this option is the most direct and effective at allocating costs to those who benefit from the HVDC's existence. While these customers may realistically 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, and does not require the complex processes associated with the capacity rights option, for example.

Contact believes that the potential efficiency benefits of postage stamping HVDC costs to offtake customers are significant, as identified by the TPAG. Because, under this option, there is no relative penalty on South Island generation, the investment inefficiencies inherent in the status quo would be eliminated, with the TPAG estimating this could produce benefits of between $14 and $51 million. These estimates are likely to be realised through projects like those identified earlier in this submission, who, practically, have their relative economics distorted by the current HVDC cost allocation methodology.

The removal of the HAMI determination would also eliminate the investment and dispatch inefficiencies inherent in the status quo cost allocation methodology. The TPAG's estimates of the combined potential efficiency gains of $0 to $47 million are significant.

The TPAG raises concerns about the likely step change in welfare that would occur under postage stamping to offtake customers, and note that this would have flow-on effects to regulatory certainty. Contact has previously submitted that these welfare transfers could be managed through transitioning from the status quo[13], so we are pleased that this option is considered.

Contact does not believe that the concerns noted around immediate and certain up-front transfers of value (compared to future expected wholesale price reductions) are 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 (and hence a return on that investment) over the assets' useful life. 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.

[13]See Contact Energy submission on *"Consultation Paper Transmission Pricing Review: Stage 2 Options"*, Prepared by the Electricity Commission, July 2010.

Postage stamp transition option

In addition to the material efficiency gains noted above for the postage stamp to offtake customers option, the option of transitioning toward postage stamping of HVDC costs over time eliminates any concerns around the potential impacts of welfare transfers. Again, Contact has previously, and continues to, support such transition options as they reduce perceived regulatory uncertainty and provide for the market to adapt to changes over a defined period. Particularly where costs to be transitioned over time (but initially allocated to South Island generators) are set at a fixed rate, participants will be able to accurately predict the transfers involved, and will adjust accordingly.

This option is also most likely to align with the Authority's FTR proposal in terms of the treatment of rentals. Contact 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.

At between $11 and $96 million, the estimated net benefits of the option to transition to postage stamping of HVDC costs to offtake customers are material.

The TPAG's estimates of the net benefits of alternative options are material

Table 27 of the consultation paper summarises the relative costs and benefits of options considered by the TPAG. Contact understands that there was no split conclusion in relation to these assessments.[14]

That table indicates that there are alternative options to the status quo allocation of HVDC costs which could produce material net benefits. 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.

[14] But that there was in terms of whether they were sufficient to justify a change to the status quo.

Contact supports the TPAG majority recommendation – the estimated net benefits are sufficient to justify a change from the status quo HVDC cost allocation

Contact submits that the potential net benefits identified in relation to the postage stamp transition option for HVDC cost allocation are material, and are sufficient to justify a change from the status quo methodology. The TPAG majority favoured option classifies the HVDC appropriately as another interconnected transmission asset and its cost recovery accordingly.

While the TPAG's analysis has identified benefits associated with other methodologies (e.g. MWh allocation to South Island generators), the postage stamp transition option appears to produce the highest estimated net benefits; both in quantitative and qualitative terms. Any additional costs associated with securing incremental benefits (in moving from the MWh allocation to the postage stamp transition option) would be incorporated into the analysis, but the TPAG's approach still produced a higher net benefit for the TPAG majority's favoured option.

Given that the Authority intends to introduce Code changes supported by quantitative analysis of options which produce net benefits of a size potentially smaller than those estimated by TPAG (e.g. the locational price risk proposal for FTRs), Contact submits that the net benefits are of a materiality that can, and should, lead to a Code change.

Importantly, Contact believes that the transition element of the option favoured by the TPAG majority eliminates the primary concerns historically identified by opponents to the methodology i.e. wealth transfers. The use of a pre-determined, fixed incentive free allocation as part of that transition is a sensible mechanism to stabilise signals to participants during that transition. In Contact's opinion, there are no issues attributed to the views of the TPAG minority that would suggest the estimated net benefits of the TPAG majority's favoured option are not potentially achievable.

Contact also believes that arguments about the postage stamp transition option introducing immediate and certain up-front transfers of value (compared to future expected wholesale price reductions) are irrelevant.

Deep or shallow connection

Contact has generation assets that are connected to the grid with varying degrees of depth of connection, and supports the existing definition of (AC) Connection assets. Contact submits though, that 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 submits that to connect renewable generation that is remote from the grid would typically require investment in new spur line (connection) assets – which would be at a direct cost to a dedicated generator and hence would probably be owned by the generator. We would not expect that Transpower would build these types of assets and then seek to treat them as interconnection assets. If existing connection assets were treated as interconnection though, it would encourage generation in more remote areas. The current environment may create a deterrent for new generators to be reallocated these sunk connection charges, thereby deferring marginal renewable projects. Even if a generator attempts to embed such generation, the local lines company would typically seek a sharing of these connection assets.

A shallower grid that, for example, would include all load spur lines (as interconnection) but exclude specific substation connection assets and dedicated generation spur lines, is also likely to defer or avoid transmission investment (through lower cost generation connection) and increase competition, and in doing so would benefit some remote communities with a relatively small initial increase in interconnection charges.

Contact believes that flow tracing is too complex for customers to understand and may change significantly from year to year. Contact submits that the demarcation between connection and interconnection should therefore be determined pragmatically and is largely satisfied with the existing approach.

Static reactive compensation

Contact submits that as assets are sized on kVA rating, demand charges for those assets should simply be charged on a $/kVA basis (rather than $/kW). Contact believes that this would incentivise lines companies to improve power-factors at their source. Contact believes that this rating should be applied as a nationwide standard (rather than at a regional level), with a technical minimum of 0.95 lagging (at RCPD periods) being set in regulation.

Specific answers to consultation questions

Do you agree with the TPAG's assessment that there does not appear to be a demonstrable economic benefit from enhanced locational signalling to grid users through transmission charges to defer economic transmission investments decision? If not, please provide your reasons.	Yes.
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?	Yes. Contact supported the changes to the framework which were pragmatic.
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?	Yes.
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?	Yes, the TPAG has identified appropriate efficiency considerations.
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 particularly 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.	Yes, the potential efficiency gains identified provide analytical support for issues which participants can observe in the market, resulting from the current HVDC cost allocation.
Do you agree with the range of HVDC options identified for assessment? If not, why not?	Yes.
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.	No. Contact appreciates that not all considerations can be quantified for each HVDC option.
What is your position on the two views? Do you have further evidence to support either the majority or minority view?	Contact supports the majority view, which provides analytical evidence of efficiency gains possible by moving away from the status quo cost allocation.
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.	Yes, Contact believes that the analysis provides pragmatic estimates of costs and benefits of the relative options where these are possible. The analysis supports the selection of the postage stamp transition option as the preferred option.
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.	No. Contact believes that postage stamping HVDC costs to offtake customers is the most efficient option.
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.	Contact believes that the postage stamp option should be recommended to the Authority, and that the fixed charge proposed, and the 10 year term eliminate any concerns around wealth transfers, while providing certainty for South Island generators during the transition.
Do you agree with the TPAG's conclusion that any further analysis of deeper connection options requires close coordination with the Commerce Commission?	Some co-ordination with the Commerce Commission is likely to be required. Contact supports the Commerce

	Commission looking at ways lines companies can be rewarded for reducing transmission charges through transmission alternatives, technology or improved load management practices.
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.	Contact believes efficiency gains are likely to be at the lower end of the range provided.
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?	Contact supports the range of options, but does not support "but for" or load flow approaches due to continued potential for disagreement of level of application. Contact supports a more practical definition of connection which should be only the substation assets and exclude dedicated generation spur lines. This would remove any unintended perverse incentives and avoid any chance of major change due to grid reconfiguration or development in the future.
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.	Contact would like to see the impact of a more shallow connection option as described above.
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.	Contact is hesitant about the value of further extensive analysis.
Do you agree with the TPAG's overview of the background on SRC and the identification of the regulatory failure described in this section? If not, why not?	Yes. There is a failure with the current arrangements and a $/kVA pricing incentive is required. A kVAr charge that is supposed to reflect the investment costs of SRC equipment is the same thing and could be derived from the simple kVA charge.
Do you agree with the selection of SRC options selected for assessment? If not, why not?	No, Contact believes a simple kVA charge should be included.
For option 4, the amended kvar charge, do you support the approach of retaining a minimum point of service power factor for the UNI and USI regions as a backstop measure? If so, do you support the recommended approach of providing a penalty rate for demand in excess of the minimum?	Contact supports a backstop measure of 0.95 and an additional penalty rate if this is exceeded.
The TPAG has assessed the amended status quo and the amended kvar charge options against the efficiency considerations 1 - 6. Are there aspects of this assessment that you disagree with or could provide more information on? Please provide details.	Contact agrees, but would prefer to see a simple kVA charge for offtake
Do you agree with the TPAG's summary of the costs and benefits of the options assessed and its observations? If not, why not?	Yes.
Do you think it appropriate that minimum power factor requirements are retained in the Connection Code for points of service in the LSI and LNI regions, when a view has been taken that such arrangements are unenforceable in the UNI and USI regions and thereby amount to a regulatory failure?	Yes. Minimum power factor requirements must be included and enforceable at GXP level and should apply to all regions (not only USI and UNI).

In your experience are there any other issues that arise from the current prescription within the Connection Code of minimum power factor for points of service in the LSI or LNI regions? Please provide background relevant to any issues you identify.	A simple kVA charge would resolve these problems.
If you have identified issues in the previous question, do you think an approach similar to the amended kvar charge option, possibly incorporating a penalty charge for reactive power demand in excess of a set minimum power factor, would provide a better approach to address the issues you have identified? Are there other options that should be considered?	A simple kVA charge would resolve these problems.
Do you support the recommended introduction of an amended kvar charge (option 4) into the TPM? Please provide reasons.	Yes – but Contact would prefer to see a simple $/kVA charge.
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?	No.