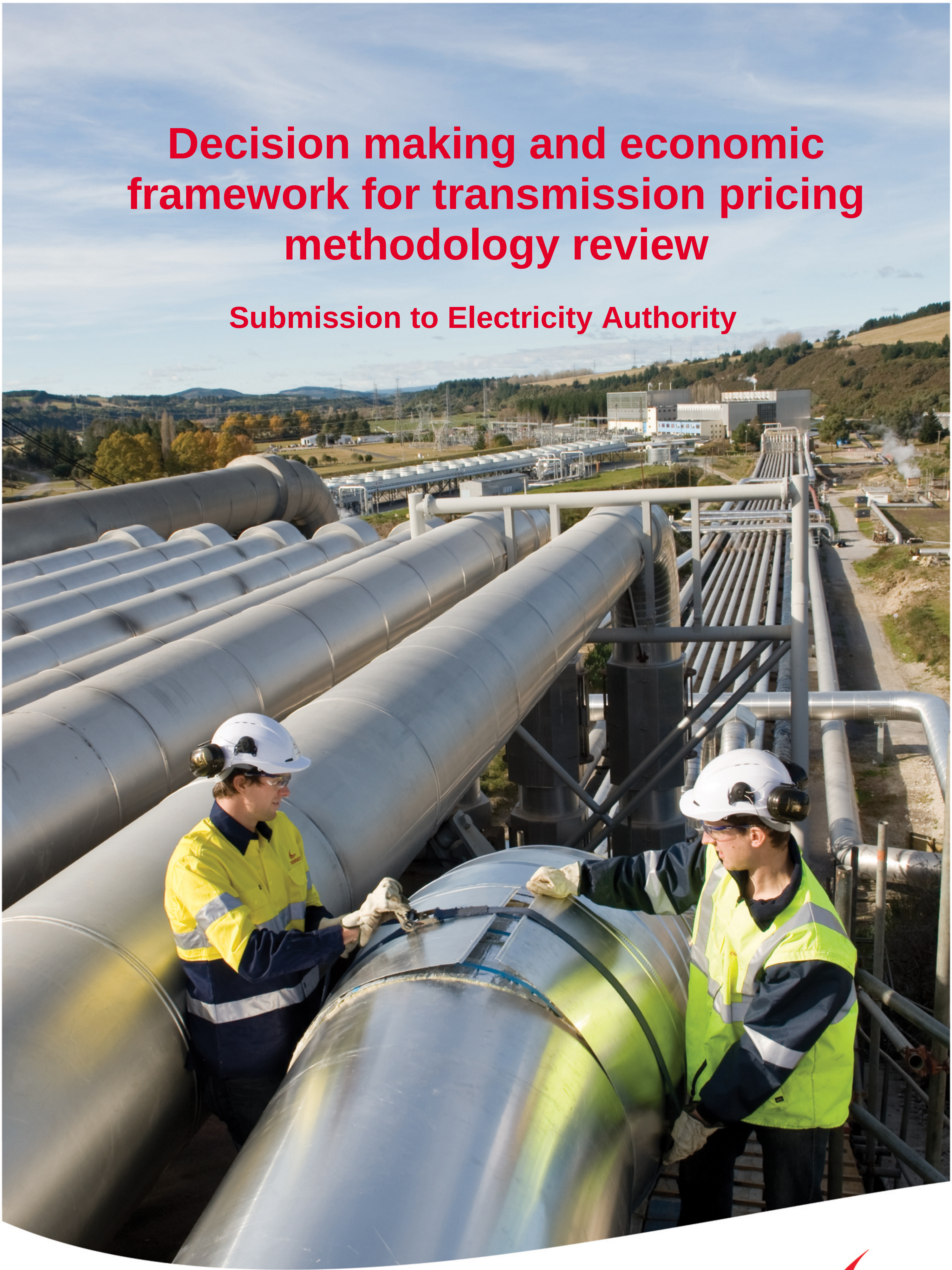
Decision making and economic framework for transmission pricing methodology review

Submission to Electricity Authority



From Contact Energy

This submission by Contact Energy Limited responds to a consultation paper to obtain feedback on its proposed decision-making and economic framework for the Transmission Pricing Methodology Review.

For any questions relating to our submission, please contact:

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Summary

Contact Energy Limited (**Contact**) submits that any change to the Transmission Pricing Methodology (**TPM**) should be on the basis of clearly demonstrated efficiency gains. The assessment of the potential for efficiency gains must take into account the extent of transmission investment that is already committed as well as being workable in what is an already complex environment.

In the "Decision-making and economic framework for the Transmission Pricing Methodology Review" consultation paper (**Consultation Paper**) the Electricity Authority (**EA**) has not made a case that there is any merit in developing market-based solutions or the exacerbator pays/beneficiary pays approaches for interconnection and/or HVDC link assets. For these to prevail it is necessary to show that they would be capable of either driving efficiency in future, still-to-be-made transmission/generation investment decisions or improving the recovery of existing, sunk costs so as to create less distortions (such as through more efficient dispatch). Contact submits that this is not and cannot be shown and argues:

- a market-based mechanism ignores the strong natural monopolistic characteristics of transmission assets (i.e. Transpower), would consequently be unworkable and is not only unsupported in academic literature but is without precedent internationally;
- the exacerbator pays/beneficiary pays approach amounts to a very deep connection charge regime, which would be contentious, non-transparent and leave the industry in a state of flux. There is significant potential for this approach to drive inefficiencies by distorting investment behaviour as potential exacerbators seek to avoid being categorised as such.

Contact submits that proper application of the decision making and economic framework summarised in Figure 1 of the Consultation Paper (**Decision Making Process**) proposed by the EA would lead to the conclusion that interconnection and/or HVDC cost allocation should be based on postage stamp transition (**PST**), incorporating a transitional, incentive-free allocation to existing South Island generators. This approach is likely to achieve the best outcome in terms of economic efficiency, without necessitating the large price impacts and wealth transfers likely to be associated with more radical proposals, and which themselves risk damaging market conduct as parties seek to avoid their consequences.

Contact submits that this conclusion is consistent with achieving the statutory objective of the EA. A durable and stable TPM, free of ongoing controversy, offers the best outcome for the overall efficiency of the electricity industry for the long term benefit of electricity consumers.

Contact submits that PST allocation is consistent with, and leverages off, the work and analysis of the majority view of the Transmission Pricing Advisory Group (**TPAG**) as published in their Report dated 31 August 2011, as well as the prior work of the CEO Forum. Contact is concerned that the EA's attempt to revert to 'first principles' – all of which have been previously identified, and rejected in light of good economic reasoning – for transmission pricing moves away from the common ground that was established through the majority views of TPAG and the CEO Forum. This will further delay the selection and implementation of a durable and stable solution to transmission pricing.

Market based approaches to charging

Contact submits there is no merit in the EA devoting further effort to developing market-based TPM charges for interconnection and/or HVDC link assets.

The EA's preliminary view of a market based approach to charges is that "it would prefer that charges are established by the interaction of buyers and sellers rather than charges that seek to replicate the outcome of market interactions".

Contact submits that this view ignores the facts: that the provision of transmission services in New Zealand (both as to prices and investment decision making) does not result from a competitive market, cannot be so, and should not be expected to do so. Why? Because transmission assets have strong natural monopoly characteristics, which arise through substantial economies of scale, the physical laws that govern electricity flows and the potential for free-riding that is intrinsic to an open access grid. Transpower is a natural single supplier and should be expected to remain so. To suggest that it would be possible for there to be 'an interaction of buyers and sellers in a workably competitive market' is to ignore these fundamental characteristics of the transmission service.

To impose a market-based mechanism would require a system of restricted physical rights to transmission capacity. This is inconsistent with the market system comprised of nodal pricing, centralised dispatch and open access to the grid. The development of such a mechanism within a centrally dispatched system would be unprecedented internationally, as well we being unsupported by academic literature.

Before contemplating any significant change, there must be an empirical assessment of the potential for economic benefits. This must also take into account the current state of investment commitment. Given the significant committed programme, investment decisions required in the foreseeable future are relatively minor. The key efficiency issue is therefore the efficient utilisation of the existing and committed grid. The grid upgrade will “flatten” the transmission risk profile and remove barriers to entry; imposition of a market-based approach would be counter to this goal and would reduce dynamic efficiency.

Contact submits that the undesirable consequences of imposing an additional market onto the existing electricity market will be to:

- add significant complexity, inefficiency and uncertainty to the process of centralised dispatch;
- result in perverse, inefficient outcomes (i.e. under-utilisation) if available capacity is not acquired, or if the administrative complexity and cost of acquiring and trading in physical rights cause any existing capacity to ‘lie idle’;
- add further complexity to the financial transmission rights (**FTR**) regime with the potential to render the FTR regime unworkable even before it is implemented;
- fragment the market, which is counter to the benefits of the Pole 3 upgrades as a capacity-based market would provide uncertainty as to the availability of capacity to support efficient dispatch;
- lessen competition as physical constraints removed by the upgrade are replaced by non-physical market-based, potentially monopolistic constraints;
- will provide market power to certain participants who are able to purchase and withhold capacity to the benefit of their generation portfolio;
- add uncertainty, which will be factored in as a risk premium in the secondary market, i.e. transmission risk premium that will be removed by grid investment will be replaced by market capacity risk due to unpredictable hydrology;
- impose additional EA levys as a result of setting up and maintaining a complex market-based allocation methodology.

The likely effect of the added layers of complexity is to decrease market efficiency, increase administrative costs, be a barrier for new entrants to the electricity market leading to reduced competition. This would be a perverse outcome given the EA’s acknowledgement that competition is an important tool to encourage efficient outcomes.

Administrative based approaches to charging: exacerbator pays/beneficiary pays/alternative charging options

Contact submits that the EA should adopt its fourth ranked preference of administrative approaches to TPM charges of 'other charging options'. Contact submits that an exacerbator pays/beneficiary pays approach would be administratively unworkable, encourage inefficient avoidance decisions and fail to achieve the EA's goal of providing a durable and stable market free of controversy.

Exacerbator Pays

The exacerbator pays approach, as proposed by the EA, is based on the premise that "…to the extent it is practicable those making decisions relating to the grid face the full social costs of their decisions and not just their private costs". The EA's definition of an 'exacerbator' as 'a party whose action or inaction led to the need to undertake an activity' means this approach would only work for future grid investments. Given the level of already committed investment, imposition of this approach has no relevance to recovering existing costs – even though this function represents the substantial task that the TPM must address.

Setting aside the question of the extent to which the exacerbator pays approach would affect the recovery of existing costs, the issues raised by attempting to discern cost causation within a shared resource are complex and could themselves be expected to lead to inefficient market outcomes:

- network interactions mean that, in practice, it will not be possible to identify exacerbators clearly or in any enduring way, or to link and allocate causation of network upgrades to individual users;
- the economies of scale in transmission assets make it more socially beneficial for large investments to be made infrequently. Under the exacerbator pays approach the user who 'tipped' the system into requiring the upgrade would potentially be identified as the exacerbator and, accordingly, be allocated costs highly disproportionate to their marginal impact on the system;
- it would distort investment behaviour by incentivising behaviour to avoid being the user(s) who 'tipped' the system into requiring an upgrade.

An analysis of the Wairakei region is a good example of how application of an exacerbator pays approach would work in practice; there is enough current transmission to cover the existing geothermal base load generation in steady state. The Wairakei grid upgrades were based on the economic benefits of the next round of geothermal generation investments (Contact's Tauhara and Mighty River Power's investments) displacing more expensive thermal generation. The net benefits were positive and the grid investment was approved by the Electricity Commission. If the exacerbator pays principle had been applied then the trigger point for the investment would be delayed, requiring the overall marginal price to rise to the point of covering the generation investment and transmission cost. The economic cost of delaying geothermal investment would be contrary to the EA's statutory objectives of promoting market efficiency.

The Consultation Paper states that the retrospective application of an exacerbator pays approach may still improve efficiency by "sending a clear signal to others that they should consider the indirect costs to society of their decisions, if these differ from their private direct costs, as they will be required to bear these costs." The exacerbator pays approach is intended for use in an environment where parties have the ability to act differently, i.e. where it can influence decision making. By definition, retrospective imposition of this approach on existing committed investment decisions cannot increase efficiency – if the desired signal can be put in place for future decisions (which, for the reasons described above is highly doubtful), there is no case for reinforcing this by applying it to decisions already made. This would defeat the very purpose of the approach and may be challenged. The EA's desire for a durable and stable solution to the TPM issue would be compromised if the solution resulted in challenges.

Beneficiary Pays

In the EA's opinion a 'beneficiary' is the party who would be willing to make the investment because the private benefit of the investment exceeds the costs.

The EA acknowledges that if a beneficiary pays approach is adopted the perceived benefits of improved investment efficiency and durability will be compromised if beneficiaries cannot be cost-effectively identified.

As part of its work, TPAG assessed the beneficiary pays approach against efficiency considerations. It was accepted that there are possible benefits from applying a beneficiary pays approach to the allocation of transmission costs - however, TPAG acknowledged the following issues with the approach:

- it would require subjective and debatable judgements to be made based on, amongst other things, hydrology, wind levels and thermal plant outages. The nature of this type of contentious decision making exposes the decision maker to challenge;

- the framework for investment decision making in transmission involves the evaluation of a complex and uncertain mix of various public and private benefits. For example, replacement of the HVDC Pole 1 by Pole 3 provides a number of additional system benefits being reserves (reduced reserve requirements), security (greater overall reliability due to configuration flexibility/technical capability built into Pole 3 may facilitate development of an efficient and competitive ancillary services market), losses, and competition (creation of a national retail market), for which it is difficult to identify particular beneficiaries. As evidenced by the 'A4 GIT' 1 (Grid Investment Test) overview of the benefits provided by the HVDC upgrade, a significant proportion of the Pole 3 benefits are not attributed to the private benefit of South Island generators;
- application of beneficiary pays to existing sunk cost investments would have the potential risk of sending a signal that sunk generation investments are at risk of having transmission costs imposed on them at a later date. This is particularly a problem where payers are not given decision rights – as is the case where transmission investment is controlled by a third party;
- there are significant difficulties associated with identifying and allocating benefits when investment decisions are subject to economies of scale (who pays for interim, spare capacity that benefits both existing and future market participants?), and when complex grid effects that must be taken into account (wet North Island/dry South Island, dry North Island /wet South Island, dry/dry) mean the HVDC link flows in both directions – this is itself an indicator of the potential complexity surrounding that one asset.

Unless these real world challenges are recognised and incorporated into the decision making process then the long term impact on South Island customers is increased prices. While South Island large consumers have not borne the HVDC charge, they will increasingly pay a higher price for energy due to the current blunt beneficiary pays signal that the HVDC charge sends for South Island generation investment. This is showing up in the forward curve post the HVDC Pole 3 commissioning and the subsequent south transfer risk reduction, as highlighted in figure one.

[1] https://www.ea.govt.nz/document/15958/download/our-work/advisory-working-groups/tpag/tpag-meeting-28-march-2011

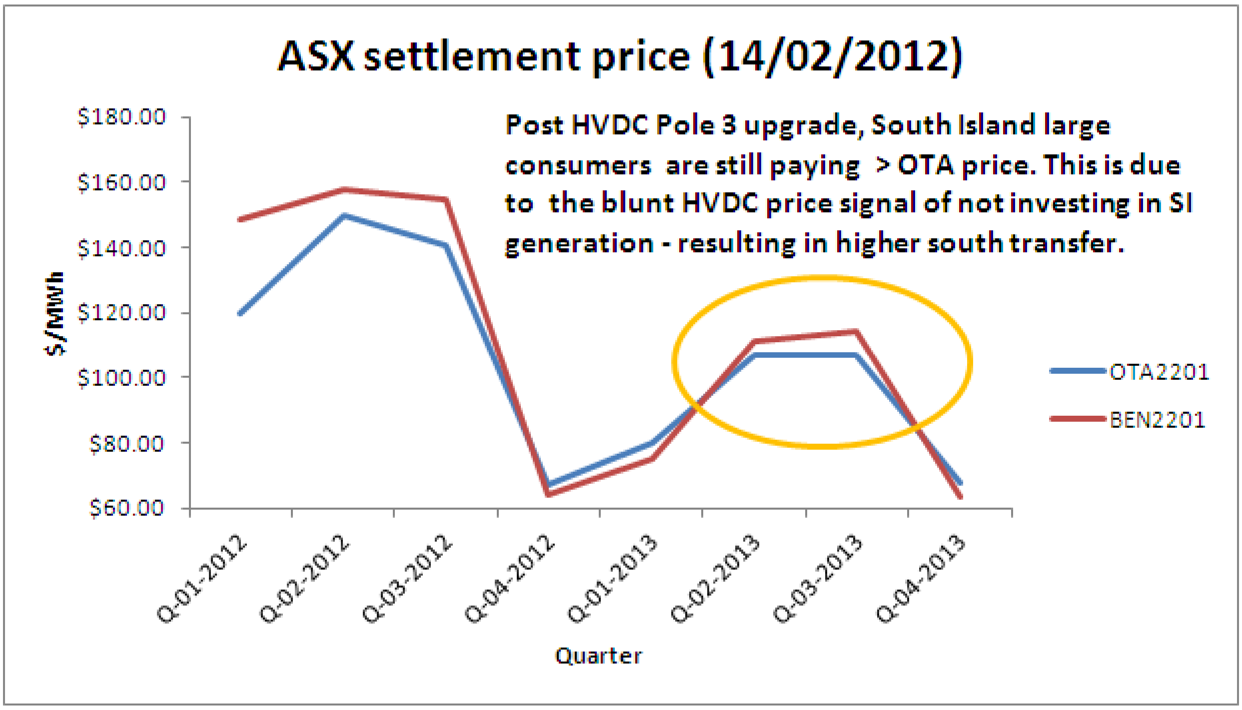

Figure one

Alternative charging options – Postage Stamp Transition

Based on the above analysis, and further to Contact's previous submission on interconnection and HVDC allocation, Contact supports postage stamp transition and believes that this option:

- appropriately classifies the HVDC as an interconnected transmission asset, with its costs recovered accordingly;
- aligns well with the EA's proposal for managing location price risk (i.e. FTRs); and
- effectively deals with concerns identified by opponents that the methodology would result in wealth transfers.

Process Issues

Given the Consultation Paper evidences a significant departure from the approach promoted by the CEO Forum and the majority of TPAG members, Contact submits that there has been insufficient time allocated to this consultation. The "Next Steps" process concerns Contact. Contact wishes to record that it has committed considerable resources to the TPM issue over the years and is concerned that the Consultation Paper does not give sufficient weight to all the work and the common ground that has been achieved to date. The move away from the common ground that was established moves the industry back to a state of high and unwarranted regulatory uncertainty.

Specific answers to Questions

No.	Question	Contact Energy response
Q1	Do you agree with the Authority's interpretation of its statutory objective with respect to transmission pricing? If you agree, please explain why. If you do not agree, please explain how you consider the statutory objective should be interpreted with respect to transmission pricing and the reasons for your interpretation.	No, We 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 Electricity Commission's analysis and development of alternative TPMs to be reworked. A more helpful interpretation of the Authority's statutory objective would be to focus on the potential for economic efficiency gains from any proposed reforms to the TPM. Such gains may potentially arise in two basic forms, ie: (i) whether use of existing transmission capacity can be further optimised, principally through more efficient (lower cost) dispatch, for given levels of reliability; and (ii) whether the total cost of future transmission and generation investment can be reduced – through changes to the TPM that alter the pattern of generation investment in a such a way that future transmission investment costs are reduced (by more than any associated increase in generation investment costs). Offsetting any theoretical potential for such efficiency gains are the costs arising from the sheer practical complexity of introducing and working with the changes that may be contemplated under the Authority's framework - such would arise under the establishment of markets for physical rights to transmission. Contact submits that the Authority's interpretation of its statutory objective needs to shift to a much more practical, outcome-focused specification level than the abstract, high level principles that are put forward in the consultation paper.
Q2	Do you agree with the above application of the three limbs of the statutory objective to transmission pricing? If not, why not, and are there other examples of how transmission pricing can influence competition, reliability and efficiency?	No. Contact submits that application of the decision making and economic framework summarised in Figure 1 of the Consultation Paper (Decision Making Process) proposed by the EA with careful attention to the practical implications identified above would lead to the conclusion that interconnection and/or HVDC cost allocation should be based on postage stamp transition, incorporating a transitional, incentive-free allocation to existing South Island generators. This approach is likely to achieve the best outcome in terms of economic efficiency (again, defined and interpreted in the practical terms identified above), without necessitating the large price impacts and wealth transfers likely to be associated with more radical proposals, and which themselves risk damaging and inefficient market conduct as parties seek to avoid their consequences.

Q3	Do you agree that a market-based TPM would tend to promote efficiency in grid use and in investment in the grid, generation, demand management and the electricity industry? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	No. Contact submits that the EA's promotion of a market-based TPM ignores the facts: the provision of transmission services in New Zealand (both as to prices and investment decision making) does not result from a competitive market, cannot be so, and should not be expected to do so. Why? Because transmission assets have strong natural monopoly characteristics, which arise through substantial economies of scale, the physical laws that govern electricity flows and the potential for free-riding that is intrinsic to an open access grid. Transpower is a natural single supplier and should be expected to remain so. To suggest that it would be possible for there to be 'an interaction of buyers and sellers in a workably competitive market' is to ignore these fundamental characteristics of the transmission service. To impose a market-based mechanism would require a system of restricted physical rights to transmission capacity. This is inconsistent with the transmission system comprised of nodal pricing, centralised dispatch and open access to the grid. The development of such a mechanism within a centrally dispatched system is without precedent internationally, as well as not supported in academic literature.

Q4	Do you agree that a market-based TPM is likely to be more durable and stable than approaches involving administered charges? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	No. The concept of market-based transmission pricing is without precedent internationally and is simply not supported in the academic literature. It cannot provide a durable and stable solution for the following fundamental reasons: • add significant complexity, inefficiency and uncertainty to the process of centralised dispatch; • result in perverse, inefficient outcomes (i.e. under-utilisation) if available capacity is not acquired, or if the administrative complexity and cost of acquiring and trading in physical rights cause any existing capacity to ‘lie idle’; • add further complexity to the financial transmission rights (FTR) regime with the potential to render the FTR regime unworkable even before it is implemented; • fragment the market, which is counter to benefits of Pole 3 upgrades as a capacity-based market will provide uncertainty as to the availability of capacity to support efficient dispatch; • lessen competition as physical constraints removed by the upgrade are replaced by non-physical market-based, potentially monopolistic constraints; • will provide market power to certain participants who are able to purchase and withhold capacity to the benefit of their generation portfolio; • add uncertainty, which will be factored in as a risk premium in the secondary market, i.e. transmission risk premium that will be removed by grid investment will be replaced by market capacity risk due to unpredictable hydrology.
Q5	Do you agree the Authority’s first preference should be to adopt market-based approaches to TPM charges wherever it is confident such charges will be efficient and their implementation will be practicable and that any Code changes needed to do so comply with the Authority’s Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	No. Before contemplating any significant change, there must be an empirical assessment of the potential for economic benefits. This must also take into account the current state of investment commitment. Given the significant committed programme, investment decisions required in the foreseeable future are relatively minor. The key efficiency issue will therefore be the efficient utilisation of the existing and committed grid. The grid upgrade was intended to “flatten” the transmission risk profile and remove barriers to entry; imposition of a market-based approach would be counter to this goal and would reduce dynamic efficiency

Q6	In light of TPAG's views, do you consider there would be any merit in the Authority devoting further effort to developing market-based TPM charges for interconnection and/or HVDC link assets? If so, what are your reasons and how do you think this would be best progressed? If not, what are your reasons?	No. Contact submits there is no merit in the EA devoting further effort to developing market-based TPM charges for interconnection and/or HVDC link assets. Contact submits that implementation of a market-based TPM charge ignores the facts: the provision of transmission services in New Zealand (both as to prices and investment decision making) does not result from a competitive market, cannot be so, and should not be expected to do so. Why? Because transmission assets have strong natural monopoly characteristics, which arise through substantial economies of scale, the physical laws that govern electricity flows and the potential for free-riding that is intrinsic to an open access grid. Transpower is a natural single supplier and should be expected to remain so. To suggest that it would be possible for there to be 'an interaction of buyers and sellers in a workably competitive market' is to ignore these fundamental characteristics of the transmission service.
Q7	Do you agree the Authority's second, third and fourth ranked preferences should be to adopt the administrative approaches to TPM charges of exacerbators pay, beneficiaries pay and other charging options wherever it is confident such charges will be efficient, implementation will be practicable, and that any Code amendments needed comply with the Authority's Code amendment principles? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	Contact submits that the EA should adopt its third ranked preference of administrative approaches to TPM charges of 'other charging options'. Contact submits that an exacerbator pays/beneficiary pays approach would be administratively unworkable, encourage inefficient avoidance decisions and fail to achieve the EA's goal of providing a durable and stable market free of controversy.
Q8	Do you agree these actions can exacerbate investment? Are there other actions and, if so, what are they?	No, new generation, especially renewable, locates where the fuel resource is located. The identification of an exacerbator by reference to the actions or inactions it takes fails to recognise this fundamental driver of generation location decisions. An analysis of the Wairakei region is a good example of how application of an exacerbator pays approach would work in practice; there is enough current transmission to cover the existing geothermal base load generation in steady state. The Wairakei grid upgrades were based on the economic benefits of the next round of geothermal generation investments (Contact's Tauhara and Mighty River Power's investments) displacing more expensive thermal generation. The net benefits were positive and the grid investment was approved by the Electricity Commission. If the exacerbator pays principle had been applied then the trigger point for the investment would be delayed, requiring the overall marginal price to rise to the point of covering the generation investment and transmission cost. The economic cost of delaying geothermal investment would be contrary to the EA's statutory objectives of promoting market efficiency. Contact has not considered whether other actions would be appropriate measures as it believes this approach is fundamentally flawed.

Q9	Do you agree that exacerbators should be identified by determining which party or parties have the ability to act differently, thereby avoiding the need to augment the network? Is there an alternative approach? If so, please provide details.	No. The exacerbator pays approach, as proposed by the EA, is based on the premise that "…to the extent it is practicable those making decisions relating to the grid face the full social costs of their decisions and not just their private costs". The EA's definition of an 'exacerbator' as 'a party whose action or inaction led to the need to undertake an activity' means this approach would only work for future grid investments. Given the level of already committed investment, imposition of this approach has no application to recovering existing costs – even though this function represents the substantial task that the TPM must address. Setting aside the question of the extent to which the exacerbator pays approach would affect the recovery of existing costs, the issues raised by attempting to discern cost causation within a shared resource are complex and could themselves be expected to lead to inefficient market outcomes: • network interactions mean that, in practice, it will not be possible to identify exacerbators clearly or in any enduring way, or to link and allocate causation of network upgrades to individual users; • the economies of scale of transmission make it more socially beneficial for large investments to be made infrequently. Under the exacerbators pays approach the user who 'tipped' the system into requiring the upgrade would potentially be identified as the exacerbator and, accordingly, be allocated costs highly disproportionate to their marginal impact on the system; • it would distort investment behaviour by incentivising behaviour to avoid being the user(s) who 'tipped' the system into requiring an upgrade. Contact has not considered an alternative approach to identifying the exacerbator as it does not believe the approach has merit.
Q10	Do you agree with the assessment of the price that should apply to exacerbators? Do you agree with the assessment of how exacerbators pay should apply in practice? Do you agree with the proposed approach for identifying the preferred option or options for applying exacerbators pay? Please provide explanations in support of your answers.	No. The exacerbator pays approach, as proposed by the EA, is based on the premise that "…to the extent it is practicable those making decisions relating to the grid face the full social costs of their decisions and not just their private costs". The EA's definition of an 'exacerbator' as 'a party whose action or inaction led to the need to undertake an activity' means this approach would only work for future grid investments. Given the level of already committed investment, imposition of this approach has no application to recovering existing costs – even though this function represents the substantial task that the TPM must address.

Q11	Do you agree these considerations should be taken into account under an exacerbators pay approach? Please provide an explanation in support of your view.	No. The exacerbator pays approach is intended for use in an environment where the consequences of decisions by particular parties can readily be discerned from one another, and where those parties also have the ability to act differently, i.e. where it can influence decision making, and where such changed decisions reduce future transmission costs.
Q12	Do you agree that these ways can be used to identify beneficiaries? Are there others? If so, please provide details.	No. The Authority's analysis ignores the practical implications of attempting to identify beneficiaries in the NZ electricity market.
Q13	Do you agree with the assessment of the price that should apply to beneficiaries? Do you agree with the assessment of how beneficiaries pay should apply in practice? Please provide an explanation in support of your answer.	No, Contact submits that the example provided by the EA in Appendix B drawing on the price paid for Whirinaki is not in fact correct. Contact was the purchaser of Whirinaki and is unable to reconcile the numbers. Contact would be happy to work with the EA to clarify the story the EA is seeking to tell with this example.
Q14	Do you agree that prima facie the increase in transmission costs in the next few years may provide incentives for some direct connect customers to disconnect from the grid? Please provide any evidence and an explanation in support of your answer.	The possibility of an industrial disconnecting from the grid as provided is not plausible. Connection to the grid provides a relatively high power quality connection relative to being disconnected and being supplied by a local generator of which the SRMC would be far higher than the equivalent market energy price. Adding the HVDC charge to the HVAC charge as provided by the EA does not make sense, this would not provide a ~ 50% uplift in costs as provided by adding the two charge rates. The 2011/12 total HVAC revenue requirement is \$566m and the HVDC is \$117m, adding the HVDC revenue requirement to the existing HVAC would provide an uplift of 117/566 = ~20%.
Q14	Are there other alternative pricing options? Do you agree with the assessments of how incentive free and postage stamp pricing should be applied in practice? Please provide reasoning in support of your answer.	Based on the included analysis, and further to Contact's previous submission on transmission and HVDC allocation Contact supports postage stamp transition and believes that this option: • Appropriately classifies the HVDC as an interconnected transmission asset, with its costs recovered accordingly; • Aligns well with the EA's proposal for managing location price risk (i.e. FTRs); and • Effectively deals with concerns identified by opponents that the methodology would result in wealth transfers. This option is also most likely to align with the EA'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.