Submission on the Electricity Commission's Consultation Paper on Transmission Pricing Review: Stage 2 Options

From

Contact Energy Limited

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Introduction

Contact Energy Limited ("Contact") welcomes the opportunity to provide feedback on the Electricity Commission's ("the Commission") consultation paper: Transmission Pricing Review: Stage 2 Options ("the options paper").

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Executive Summary

Incentives to defer or avoid reliability investments

Contact believes that nodal pricing, the Grid Investment Test ("GIT") mechanism and deep connection are the best tools for providing appropriate and accurate price signals, and that these signals are key to informing decisions around the value of deferring or avoiding reliability transmission investments. Such signals will help ensure the efficient allocation of resources over time.

We therefore support the Commission's finding that there is likely to be limited value in providing for an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation.

Where the options put forward by the Commission (bespoke postage stamp, flow tracing and improving the transmission alternatives regime) have characteristics that support the deepening of connection assets they should be developed further.

The treatment of HVDC costs

Contact supports the Commission's finding that the lack of benefit in a locational signal has repercussions for the suitability of the existing HVDC cost allocation methodology.

The Commission has identified a number of issues with the current methodology that it believes require attention, due to adverse impacts they are likely to have on operational and investment decisions. They also note that there are likely to be net costs from the distortions created by the existing methodology, largely driven by the impacts on the real economics of generation options and the disincentives to operate existing plant efficiently and build new peaking capacity. These concerns support Contact's belief that both the classification of the HVDC assets as connection assets, and the allocation of these costs to only South Island generators was, and still is, inappropriate.

The options paper also raises questions around the applicability of factors that supported (in the Commission's view) this treatment of HVDC assets. Contact believes that inconsistencies with other market developments such as the MDP initiatives (particularly the locational price risk initiative) only compound the problems with the existing methodology.

Options for development in stage 3

Contact does not believe the status quo option, or options that simply adjust levers within the confines of the existing methodology (i.e. the MWh and incentives free option), are likely to provide for efficient investment signals to potential new load and generation projects.

The Commission's analysis shows that the benefits of incentivising North Island generation do not outweigh the costs. Contact also submits that the desire for regulatory certainty actually supports a move toward postage stamp allocation of HVDC costs. According to the Commission's decision framework, this supports Contact's view that postage stamp allocation of HVDC costs is the most appropriate.

Contact believes that while allocating HVDC costs over load would provide the least distorted signal to consumers and investors around the full opportunity cost of their decisions, further analysis of the impacts of allocating HVDC costs over load, or a mixture of load and generation, as part of Stage 3 would be worthwhile. This analysis could be on a MW or variable MWh basis.

Contact also submits that concerns around the wealth transfer impacts of a potential change toward postage stamp cost allocation can be managed.

Introduction

The Transmission Pricing Methodology ("TPM") is essentially a fixed cost allocation framework for the recovery of Transpower's annual revenue requirement from its customers and hence the implications of the framework for market participants are important.

Contact agrees with the Commission's objective[1] in the options paper that this methodology should be applied in a way that encourages:

- efficient use of the transmission network and operation of the power market in real time; and
- efficient investment in new load and generation projects (including load management) which will influence future demand on the transmission network and the need for transmission investment.

Contact also agrees with the Commission's observation that the TPM has the potential to influence the locational choices of generation and the bidding behaviour of generators.

More importantly though, it can and should impact on the decisions of consumers, and hence the signals to those consumers must be visible, and reflective of the real opportunity costs of their decisions. Such signals will provide for the efficient allocation of resources over time.

Contact firmly believes that nodal pricing, the GIT mechanism (ensuring that transmission investments must provide net national benefits) and deep connection are the best tools for providing appropriate and accurate price signals in order that these efficiency gains are realised.

These principles underpin our comments below.

Proposed refinement of process

Contact supports the Commission's narrowing of the scope of the TPM review process to focus on:

- Options for providing incentives for participants to take action to defer or avoid reliability transmission investments where there are benefits in doing so; and

[1] *"Consultation Paper – Transmission Pricing Review: Stage 2 Options"*, Electricity Commission, July 2010, paragraph 2.1.3.

- Options for the treatment of HVDC costs.

We understand the need for changes to be pragmatic, and believe some of the proposals put forward for consideration are not. Some proposals do not seem to account for how the wider market environment has shown that a number of 'traditional' arguments for cost allocation are inappropriate under a variety of market conditions. For example, proposals for the use of capacity rights are much less relevant when accounting for the easing of capacity constraints on the HVDC that will result from the pending upgrades. The fundamentals underpinning cost allocations must be enduring under a variety of conditions.

The revised and narrowed focus should be useful in moving the debate forward, as participants need certainty that the TPM will be finalised and left to 'bed in'. The regulatory uncertainty created in part by the decisions to treat various components of the grid differently must be resolved, and decisions on both AC and HVDC assets must be based instead on sound principles applied consistently.

Options for providing incentives to defer or avoid reliability transmission investments

Appropriate and accurate price signals will allow participants to make informed and efficient decisions around the value of deferring or avoiding reliability transmission investments. The opportunity cost of those investments not being made needs to be visible to decision makers.

As noted above, Contact believes that nodal pricing, the GIT mechanism and deep connection are the best tools for providing appropriate and accurate price signals. Customers should ultimately pay for the cost of transmission services, and hence we believe they should see these costs/signals in the most direct and efficient way.

The Commission has undertaken a substantial amount of work to identify whether there is value in a locational signal being provided to generation in particular. This assumes generators have the ability to respond to such signals.

The Commission's preliminary view from this analysis is that[2]:

"… there may be little justification for imposing additional transaction costs on the industry in order to introduce further locational signaling in respect of economic investments"

[2] *"Consultation Paper – Transmission Pricing Review: Stage 2 Options"*, Electricity Commission, July 2010, executive summary paragraph 14.

The Commission found that there is likely to be limited value in providing for an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation.

Contact supports this finding, particularly as it relates to the cost allocation for HVDC assets (discussed later), but also for AC asset cost allocation. The costs resulting from signals that attempt to force the market to consume a particular service, or a particularly level of service, will distort the efficient demand/supply balance for transmission services, and for electricity.

In the options paper, the Commission identifies three options which seek to provide incentives for participants to take action to defer or avoid reliability transmission investments where there are benefits in doing so. Specifically, the Commission notes that their focus (in terms of managing the TPM) is on providing incentives to invest in new generation, produce more power from existing plant at specific times or consume less in particular locations via the following mechanisms:

- Bespoke postage stamp
- Flow tracing
- Improving the transmission alternatives regime

The Commission note that the options are not necessarily mutually exclusive.

Each of the bespoke postage stamp and flow tracing options have characteristics that Contact believes are valuable; particularly the characteristics that focus on deepening the pool of connection assets, and the value that flow tracing has in identifying the number of users of energy in regions. We believe there is value in combining these elements as they will provide accurate price signals and provide, for example, for parties to be able to make price/quality tradeoffs as well as incentivising efficient transmission build. Where these characteristics provide for a deepening of the pool of connection assets this should also support the development of demand side initiatives in particular regions. Deep connection could potentially help support the development of energy intensive industries in energy exporting regions. Contact supports moves to improve the transmission alternatives regime.

All consumers need to see the full opportunity cost of their consumption (whether direct or indirect) of transmission services, as they are best placed to balance incentives; particularly with respect to price and quality. Having all consumers face transmission charges explicitly (or certainly more explicitly than is currently the case for HVDC charges, for example) will

provide them with much better information about the real costs of their consumption decisions.

The treatment of HVDC costs

In its options paper, the Commission has identified a number of issues with the current methodology that it believes require consideration, due to adverse impacts they are likely to have on operational and investment decisions.

Pending upgrades to the HVDC also mean that there has never been a more important time to ensure that the underlying signals provided by the allocation methodology for recovery of HVDC are efficient and non-distortionary. As well as the impact of the upgrades, a number of other market developments also support the need for a re-think of the impacts of the current blunt price signal.

Contact also believes that the ongoing distortion of incentives created by the current methodology indicates that many of the traditional arguments which supported the decision to treat HVDC assets as connection assets are inappropriate.

Options that simply adjust levers within the confines of the existing methodology are unlikely to be sufficient to provide for efficient investment signals to potential new load and generation projects.

The importance of efficient price signals

Much has been said in previous TPM reviews about the efficiency impacts of the current, and alternative, methodologies for allocating HVDC costs. Contact believes that simply, economic efficiency requires that consumers receive consistent undistorted signals to guide their consumption decisions, and that firms receive undistorted market signals to guide their investment (and production) decisions. In an efficient market, resources will be allocated to their highest value use.

Because of the current methodology, consumers are effectively facing (albeit indirectly) a price for transmission services that is below the total opportunity cost of supply. This price is subsidised by only South Island generators via what is analogous to a tax. This means that the level of transmission investment is unlikely to be efficient, as demand will be above a level that would be sought where price reflected the full opportunity cost of producing and transporting that electricity.

Where price signals are undistorted and consistently applied, the level of demand for a service will determine an appropriate level of investment in assets to provide that service. Therefore, HVDC assets must be classified as interconnection assets in order that price signals to consumers and producers are undistorted, so that they can make efficient decisions. These prices need to be visible to all consumers to allow them to respond where they can. Consumers should ultimately pay for transmission assets, so Contact supports them being visible in the most direct manner.

Small productive and allocative efficiency gains from appropriate HVDC treatment will lend themselves to dynamic efficiency through time. These gains are likely to be material when considering the impact of even small changes in peak demand on a high asset base (the driver of capacity being peak demand); particularly once the Pole 3 upgrade takes place.

Lack of locational price signal impact supports change to HVDC classification

The options paper notes the Commission's thinking at the time of the last TPM review in 2006, where they proposed that:

"…the primary contributors (users) to the costs of the existing HVDC assets are South Island generation plant and North Island consumers but there are efficiency gains from improving location signals" [3]

The Commission also believed that the case for the existing methodology – the allocation of HVDC costs over only South Island generators, was reasonably compelling.

We noted above the Commission's preliminary views that the benefits of such locational signals do not appear to outweigh the imposition of additional transaction costs in providing those signals. Specifically for the HVDC it notes that:

"These results could have implications for the design of the high voltage direct current link (HVDC) charges as it is an explicit locational signal to invest in generation in the North Island in preference to the South Island"[4] and that *"…consideration should be given, in the first instance, as to whether the current locational signal provided by the HVDC charges is distortionary in terms of operational and investment decisions. In other words whether the current HNDC charge creates a significant dis-benefit"*[5]

[3] *"Consultation Paper – Transmission Pricing Review: Stage 2 Options"*, Electricity Commission, July 2010, paragraph 3.3.22.
[4] Ibid, executive summary, paragraph 15.
[5] Ibid, paragraph 3.3.17.

The Commission's statements suggest that the fundamentals behind the existing methodology are inappropriate and distortionary, and that the primary signal provided by an allocation to only South Island generators (c.f. an allocation applied consistently to load or all generators) may indeed actually impose costs on the wider market. The nature of the HVDC as a facilitator of energy and ancillary service markets for the benefit of all generators and customers on a national basis supports these findings.

With the key difference between the allocation of AC and HVDC costs being the treatment as interconnection (AC) and connection (HVDC) respectively, it is reasonable to also infer that the primary reason for the concerns around the distortions on operational and investment decisions resulting from HVDC costs recovery relates to the targeted participants that costs are recovered from, and the ability of those parties to flow through to consumers; the real determinant of demand for transmission services.

This key difference also suggests that options which are largely based on the same targeted cost recovery are likely to possess the same risks of distortion to operational and investment decisions. Options that treat HVDC assets as interconnection assets should provide for less distortion, by allowing all consumers to see the full opportunity costs of their decisions.

Redundancy of other traditional arguments

Rationale from the 2005/06 review

The Commission's analysis[6] also identifies whether other components of the rationale (other than that relating to the benefits of a locational signal) that supported its 2006 TPM decision (with respect to HVDC cost allocation) have been shown to be flawed, and not consistent in a variety of conditions. We discuss some of the rationale below.

- *"The decision strongly incentivises generators to look for least costs investment decisions"* and "*Charging South Island generation plant is desirable as it sends a stronger locational signal for new plant (as it is more efficient to locate generation close to load)"*

  An allocation that did not differentiate between potential investors in generation by the location of their assets would be the only way in which least cost decisions would be made. The current methodology automatically penalises South Island generation options, even though they may be lower cost. In some cases, the impact of a relative

[6] *"Consultation Paper – Transmission Pricing Review: Stage 2 Options"*, Electricity Commission, July 2010, paragraph 3.3.22.

preference for North Island generation may have also necessitated AC transmission upgrades, further increasing the distortion in relative merit.

In terms of locational signals, we have already noted above the Commission's analysis which showed that the locational signal created by the existing methodology may actually impose costs on the market. With respect to generation being built close to load, even with the relative incentive on North Island generation, limited generation has been built close to load, particularly in the Auckland region. The proposition neglects the other key considerations that may heavily influence location of generation such as fuel availability and gas transmission for example.

- *Charging South Island generators is the least distortionary option with regard to altering decisions about consumption and investment*

The Commission has noted that operational and investment decisions may be negatively impacted on by the current allocation methodology for HVDC costs. It is difficult to see how effectively applying a tax to only South Island generators could be expected to provide efficient signals for consumption and investment, in an interconnected market such as the New Zealand market.

- *The decision is fair as the bulk of benefits of the HVDC link accrue to South Island generation plant.*

The Commission's analysis supports the view that the HVDC enables the use of scarce electricity generation resources to be more efficient. Put simply, as part of an integrated network the HVDC connects generators and consumers in the North Island with those in the South Island.

Importantly, this interconnection is not only about flows of MW between islands (the level of which varies considerably between and within years), but a wider suite of roles (dry year security, power and current modulation, voltage stability, frequency control, reserve sharing etc.) which cement its position as an asset that allows our electricity market to be a national one. Transpower operate the assets as such, seeking to maximize the net benefits to the entire market c.f. to particular participants in one island. Deeper definitions for connection assets (as noted earlier) reinforce this position. Taken to its extreme, in an efficient market with deep connection the HVDC may indeed be the only true interconnection asset in operation.

Other arguments have also been repeatedly put forward by those opposing the treatment of HVDC as interconnection assets. Their durability has also come into question, as they have been shown to be flawed under a variety of market conditions. Sound cost allocation methodologies will be relevant under a variety of conditions.

The need for regulatory certainty

Ongoing incorrect classification of the HVDC assets as connection assets will further increase regulatory uncertainty; particularly in an era where the base of HVDC assets is increasing significantly. We note (as we have in previous TPM reviews) that regulatory certainty does not mean no change at all; rather that regulatory actions should be predictable and based on sound principles.

Regulatory certainty therefore can only be achieved if regulatory decision making is based on robust logic and if regulatory discretion is constrained. The discretion used by the Commission in the previous review which resulted in the allocation of HVDC costs to South Island generators must be corrected.

Offsetting HVDC costs with loss and constraint rentals

As part of the last review of the TPM, one of the Commission's arguments for treating the HVDC on an exception basis c.f. other transmission assets was that South Island generators will[7] *"continue to receive the loss and constraint rentals which will hold [them] harmless from the financial effect of new generators in the South Island using the HVDC link"*.

While we have previously proven that the benefits from rentals do not provide full cover for South Island generators[8], this argument becomes even less relevant when considering the Commission's proposal for managing locational price risk[9]. The Commission's proposal of a 2 hub FTR model will auction off the loss and constraint rentals to any participant, meaning one of the few benefits conferred on those paying HVDC costs under the TPM will no longer be guaranteed for South Island generators. Even if South Island generators do manage to obtain these rentals via an FTR auction, it will be at a cost in addition to those incurred directly under the TPM.

[7] *"Affidavit of John Charles Gleadow"*, paragraph 15.5.
[8] "Submission to Electricity Commission on HVDC Transmission Pricing Methodology", Contact Energy, 12 December 2005, page 6.
[9] Refer "Consultation Paper Managing locational price risk proposal", Electricity Commission, 13 September 2010.

The contradiction between the TPM; which claims to associate incidence of cost with the assets' primary beneficiaries, and the proposed FTR mechanism which appropriates and then auctions these benefits, is hugely concerning and highlights how the discretionary treatment of the HVDC distorts what would otherwise be a sounds principle for managing locational price risk. The two mechanisms cannot be based on inconsistent principles.

HVDC assets require special treatment and/or have special characteristics

Contact supports the Commission's decision to rule out of consideration a number of proposals from parties which seek to continue to treat the HVDC as a 'special case'. Regulatory certainty requires consistency and this cannot be achieved where assets are treated differently for no reason other than convenience. Other interconnected sections of the national grid are extensive and/or have asymmetric flows and the TPM treats them similarly.

The Commission's assessment of the costs and benefits of the existing methodology

The Commission has undertaken useful analysis which identifies the limited benefits and material costs of the existing cost allocation methodology. We comment on these briefly below, but note the overall tenor of the Commission's analysis that the purported benefits of the existing methodology are outweighed by the costs and disincentive it creates.

The Commission notes that one of the benefits expected to be provided by the current methodology was the prevention or deferral of a new inter-island link. It is clear that there is unlikely to be the need for a new inter-island link in the foreseeable future.

The Commission notes a net cost in terms of the impact of incentivising North Island generation options at the expense of more economic South Island options (linked with the benefit of preventing or deferring the need for AC upgrades). Contact submits that the small net cost is likely to be understated, as not only are uneconomic North Island projects potentially being built out of appropriate merit order, but substantial AC upgrades to support north flow are also planned/underway which will produce costs c.f. benefits.

The Commission's provisional view that the impacts of disincentivising South Island generation plant from operating at full capacity are at the lower range of $0 - $100m may be conservative. The need for this capacity - peaking capacity in particular - continues to grow, and the costs of supply (and non-supply) during those peaks is also increasing (and could further increase based on the proposed scarcity pricing initiatives). Some generators have made public statements about their intention to remove capacity from the market that could

be used in a peaking role, thus increasing the cost of disincentivising peaking capacity that is actually available.

Contact supports the Commission's preliminary view that the cost of disincentivising South Island generators from investing in new peaking capacity is small but material. Similarly to the point about North Island generation potentially being built out of economic merit order, it may be the case that peaking capacity that would be lower cost to integrate with existing plant is not being built. This has obvious consequences for distorting signals to customers about the cost of their consumption decisions.

Overall, Contact agrees with the Commission's preliminary view that the overall balance between the costs and benefits of the current HVDC charging regime is negative. This supports the need for a change away from a methodology that is not applied consistently, and one which erroneously treats the HVDC assets as a connection asset.

Other concerns - misalignment with MDP initiatives

The objectives of the Market Development Programmes (MDP) that resulted from the Ministerial Review create further questions around the ability of the existing blunt signals to incentivise efficient investment in new load and generation projects.

The scarcity pricing and dispatchable demand initiatives in particular seek to provide clarity around the value of unserved energy, and therefore opportunities for owners of generation and load to be able to respond to undistorted price signals. Their development is a response to concerns that a lack of visibility around the opportunity cost of consumption and generation decisions was impacting on pricing and the overall efficiency of the market.

The allocation of HVDC should similarly focus on providing consistent messages as to the opportunity cost of consumption (and investment) decisions, in respect of transmission services. At present, the existing methodology means that North Island generators do not see these costs, and its incidence effectively as a tax only on South Island generators means consumers similarly lack visibility. Given the importance of the HVDC in creating and sustaining a national market for energy (and associated ancillary services), this suggests that the treatment of HVDC assets is distortionary, and the allocation of costs only to South Island generators is inefficient.

Appropriate options for HVDC cost allocation

Status quo – the existing methodology

The options paper highlights the need for a review of the existing HVDC cost allocation methodology and indeed raises some concerns around the appropriateness of the signals it creates, such as:

- the likelihood that the current locational signal provided by the HVDC charges is distortionary in terms of operational and investment decisions;
- the lack of benefit from a blunt locational signal such as that created by the existing methodology;
- the net cost resulting from the incentives created by the existing methodology, driven largely by inefficient signals to both existing and new generation;
- the redundancy of many traditional arguments that supported the existing methodology;
- the inability of consumers and investors in generation to be able to observe the opportunity cost of their decisions and the inefficiencies that creates; and
- misalignment between the existing methodology and the MDP initiatives.

Contact believes that the strength of even this preliminary analysis suggests that the existing methodology is unlikely to be appropriate. The Commission has highlighted (albeit only through preliminary analysis) that the benefits of incentivising North Island generation do not outweigh the costs. The impacts of discouraging efficient operation of existing South Island generation capacity, and of peaking capacity are also underestimated in Contact's opinion. We have also noted how the inefficiencies created by the existing methodology fuel regulatory uncertainty, and that regulatory certainty requires consistency in decision making.

Accordingly, as per the Commission's decision framework the status quo is not appropriate.

Variations to the status quo – MWh charging and incentive free allocation

At a high level, the degree of commonality between these options and the existing methodology mean than many of the cons of the status quo are also applicable to the MWh an incentive free options.

While the MWh charging option would reduce some of the distortions created by HAMI measure, it is still based on principles that the Commission has proven to be inappropriate.

Through the classification of the HVDC as a connection asset, and recovery of costs from a select group of generators, the net costs of incentivising North Island generation still remain, as do the distortions on operational and investment decisions created by a blunt price signal.

The Commission's analysis has usefully shown how, despite an alteration to minimise the distortion created by the HAMI measure, the fundamentals of the MWh option are not ideal as they do not provide consistent treatment of all interconnection assets (including the HVDC) to provide consumers and investors with efficient price signals that reflect the full opportunity cost of their decisions.

For the reasons noted above, Contact also does not believe the status quo is a suitable default as identified in the decision framework in 3.3.34 (b).

In terms of the incentive free allocation option, in Contact's view it is unlikely that a practical and sustainable mechanism can be created; certainty not while the underpinnings are still based on distorted signals which have been shown to be inappropriate. The split between existing and new generators is essentially arbitrary, and would only fuel the regulatory uncertainty that the Commission has noted it is keen to avoid. The recovery of HVDC costs needs to be consistent and provide signals to consumers and investors that have not been constrained to meet short term conditions.

In simply comparing the two options, Contact believes that the incentive free allocation option is likely to be inferior to the MWh option.

Postage stamp

As noted above, the Commission's analysis indicates that the benefits of incentivising North Island generation do not outweigh the costs.

Contact has also shown why the desire for regulatory certainty actually supports a move toward postage stamp allocation of HVDC costs, as consumers and investors will have certainty that the price signals they receive are not distorted through inconsistent treatment of similar assets.

According to the Commission's decision framework, this supports the postage stamp allocation for HVDC costs.

While allocating HVDC costs over load would clearly provide the least distorted signal to consumers and investors around the full opportunity cost of their decisions, Contact supports

further analysis of the impacts of allocating HVDC costs over load, or a mixture of load and generation, as part of Stage 3. This analysis could be on a MW or variable MWh basis.

Contact also believes that any concerns around the wealth transfer impacts of a potential change to postage stamp cost allocation can be managed. While these concerns could be considered through analysis of the form of postage stamp allocation (i.e. load, or a mixture of load and generation) they could also be managed via transitioning to the new allocation methodology over time if it were thought that step changes in prices could occur, subject to the outcome of deep connection analysis.

We note though, the Commission's stated priorities in balancing economic efficiency and impact of wealth transfers. The Commission has previously noted that[10] it *"… understands submitters' concerns about wealth transfers and agrees that these should be taken into account. However, the Commission believes it is more important to focus on economic efficiency rather than wealth transfer effects".*

[10] *"Summary of Submissions Received on Proposed Guidelines for Transpower's Pricing Methodology"*, Electricity Commission, 18 February 2005, paragraph 198.

Submission on Transmission Pricing Review: Stage 2 Options

Question No.	Question	Response
1	What, if any, bearing do you consider the Authority's proposed objective has on the review's approach to analysis and evaluation to date?	Contact maintains its view (noted in q11 of the Stage 1 submission) that the pricing principles should have been reviewed as part of the TPM review, however Contact is satisfied with the thoroughness of the review as it stands. Contact believes the Authority's objective is consistent with the Commissions statutory objectives for setting transmission pricing and sees no reason why this change should materially impact on the reviews analysis to date. Contact also sees no reason why the change from the Electricity Commission to the Electricity Authority would necessarily alter the direction of this review and we would be disappointed if there was a delay to the review programme as a result.
2	Do you agree that the Commission has identified the relevant factors in its assessment (paragraphs 3.2.6 to 3.2.13) of whether nodal pricing provides adequate signals for efficient generation and load investment? If not, please explain your reasons.	Contact supports the Commission's assessment. Nodal pricing is not perfect due to impact of step investments etc but we see this as adequate with the introduction of a scarcity price signal, and supported by the GIT and deep connection.
3.	Do you agree with the Commission's approach (outlined in paragraphs 3.2.21 to 3.2.22) to determining whether any form of additional locational signal through transmission pricing is necessary? If not, please provide reasons.	Yes, this seems a reasonable method to compare scenarios given the complexities of assessing future nodal prices.
4.	Do you agree that there appears to be limited value in providing an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation? If not, please explain your reasons.	Yes, Contact supports the Commission's assessment and view that there is limited value.
5.	Do you agree that it needs to be determined whether the current locational signal provided by the HVDC charge is causing or is likely to cause inefficient operational and investment decisions? If not, please explain your reasons.	Contact supports the Commission's view that there appears to be limited value by providing a HVDC charging signal to only South Island generators but there may be merit in quantifying this further in the stage 3 analysis. As noted previously, this blunt signal has not achieved any efficient generation investment decisions in the New Zealand. It is an inefficient allocation to a subset of participants which is distortionary due to the true opportunity cost of transmission not being fully reflected to consumers.

6.	Do you agree with the high-level analysis provided on the costs and benefits of the current HVDC charging regime? If not, please explain your reasons.	Yes. Contact supports the Commissions analysis that shows most of the reasons supporting the current methodology are of questionable relevance, and the initial costs and benefit analysis demonstrates this very clearly.
7.	Do you agree that the Commission has correctly identified the four possible options for HVDC charge? If not, please explain your reasons and provide alternative options.	Contact believes that for the reasons outlined in section 3.2.22 – 25 it is unlikely the status quo can remain a valid option. Contact also believes that the fundamental issues with the existing methodology limit the potential value of the MWh and inventive free options. The analysis suggests the benefits of dis-incentivising SI generation do not outweigh the costs, and that the focus should be on options which move costs to either load, or a mixture of generation and load, via postage stamp allocation.
8.	What are your views on the validity of each of the options?	Maintaining the status quo is not a valid option, The difference between HAMI and MWh allocation still does not address the critical issue of costs needing to be applied in a consistent way without distortions. An incentive-free allocation should be dismissed as it would introduce further distortions. See our more detailed discussion in the body of the report.
9.	Do you have specific lower-level issues around the structure and details of HVDC charging that you would like to consider in Stage 3?	Contact believes that options which consider the relative benefits of postage stamp allocation of (the equivalent of) HVDC costs over load, or a mixture of load and generation, should form the basis for the detailed discussion in Stage 3.
10.	Do you agree with the analysis provided in the section headed "Analysis of benefits of signaling reliability-driven investment"? In particular do you agree with the conclusion that any incentive through the TPM which defers future reliability-driven transmission investment will likely provide some net benefit? If not, please explain your reasons.	Contact supports the view that avoiding or deferring investment in reliability transmission assets should be encouraged where it is economic to do so. Contact also believes there would be greater benefit in optimising investment in the gas and electricity transmission network which would highlight the efficiency gains that may have deferred or avoided the NIGU and NAaN projects.
11.	The Commission has decided not to pursue the options outlined in paragraph 4.1.8. Do you agree with the Commission's assessment (including the analysis contained in section 5 of Appendix 2) that these options are not worth pursuing? If not, please explain your reasons.	Contacts supports the Commissions view that the options outlined in section 4.1.8 are not worth pursuing for the reasons provided.
12.	If the Commerce Commission proposal outlined in paragraph 4.2.16(c) is adopted for the final determination, do you think this	Yes. The local lines companies are well placed to take initiatives to lower the overall cost of transportation to consumers (such as load-control plant,

	will address the regulatory anomaly referred to above?	encouragement of embedded generation and various demands side initiatives). This will only occur if there is a financial incentive to drive these combined costs of distribution and transmission down rather than simply "pass-through" without seeking to lower these transmission costs.
13.	The Commerce Commission has identified three options alongside the status quo to defer or avoid reliability transmission investments. Do you agree that these options are worth pursuing? Are there other options which deserve further consideration? Please provide reasons.	Yes, Contact believes these options are worthy of pursuing further.
14.	Can you suggest other matters to be included in the Commission's stage 3 deliberations on charging for HVDC costs?	Contact believes that options which consider the relative benefits of postage stamp allocation of HVDC costs over load and a mixture of load and generation should form the basis for the detailed discussion in Stage 3.
15.	Do you agree with these preliminary conclusions? If not, please provide reasons.	Contact supports the view (a) that there is no economic benefit from dis-incentivising SI generation through a charge on SI generators only. Our view remains that charging only a subset of participants is distortionary and does not reflect the true cost of transmission to those best placed to respond to those signals. Therefore we do not agree with the preliminary views noted in 4.3.3 (c) and (d). While we support (b) in that the HAMI mechanism is not efficient, we do not believe the option is valid. The emphasis should be on what proportion of interconnection costs (HVDC costs being included) should be allocated to the generation/load side (on a non-distortionary basis) and how this is best allocated (peak or kWh).
16.	Do you agree that connecting parties should be able to negotiate mutually beneficial access arrangements for independently provided new connection assets? If not, please explain your reasons, giving specific examples where possible.	Yes.
17.	The Commission has developed three options that it considers have potential to encourage efficient investment in static reactive power. Which of these options do you consider best encourages this objective? Please give reasons.	Contacts believes that making the current interconnection kW charge a kVA charge, with a minimum acceptable level of power-factor (measurement at peak time) would be an effective improvement. This supports our earlier view that distributors should be encouraged to lower transmission charges if they were financially incentivised for doing so.
18.	Are there other options for the allocation of static reactive power costs that the Commission should pursue?	No comment.