Response to TPAG's Transmission Pricing Discussion Paper

From the Electricity Networks Association

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1. Introduction

1. The ENA welcomes this opportunity to submit on the Transmission Pricing Advisory Group's ("TPAG's") *Transmission Pricing Discussion Paper* ("Discussion Paper").

2. The issues raised by TPAG are seen as important by ENA Members, and despite the fact that transmission charges are currently a recoverable cost under the Commerce Commission's regime; our Members do take a strong interest in transmission pricing. In particular, we see that transmission pricing issues are not narrowly limited to the technicalities of the relative efficiencies of different charging approaches, but need to be seen in light of overall market arrangements, and their perceived credibility.

3. The current consultation addresses three key issues:

   a) HVDC pricing;
   b) Static reactive compensation; and
   c) The depth of connection charges.

4. In summary, ENA:

   a) Supports the status quo and opposes postage stamp pricing for HVDC charges;
   b) Does not support the TPAG majority view that there should be a transition from the current HVDC charge on South Island generators to postage stamp charges on loads. We concur with the TPAG minority view that the efficiency gains are minor and uncertain in relation to the certain increase in transmission charges. ENA would support a refinement of the allocation methodology to mitigate the negative impacts on South Island generation investment and dispatch decisions, such as allocating costs on the basis of MWh on the basis of a rolling three year average;
   c) If, contrary to ENA's submission, the Authority ultimately comes to a view that the HVDC charge should be reallocated to consumers, then ENA submits that a transition approach should be preferred. We note that there are transition options set out in the Discussion Paper (7, 9 and 10), which have higher benefits to consumers.
   d) In principle we support a kvar charging regime to address power factor issues in the upper North and South Islands. We recommend further work is undertaken to consider and, if necessary, refine the ranges where kvar charges are triggered; and

e) Supports further analysis of different options for the depth of connection charges. Most importantly the Authority needs to ensure alignment with the Commerce Commission's regime, which currently does not incentivise EDBs to make efficient investment decisions in regard to transmission alternatives.

5. We address each matter in more detail in the following sections.

2. HVDC Pricing

Introductory comment

6. Please make this the last time!

7. ENA and some of its Member companies have been supportive of the review of the transmission pricing methodology since the Electricity Commission issued the first transmission pricing guidelines. This was on the basis that no long-term price signals existed to enable generation (especially) and loads to make locational trade-offs that would enhance the efficiency of the electricity market. In the Electricity Commission's first consultation paper[1] in this review, it noted various options under evaluation including:

a) Tilted postage stamp approaches;
b) Augmented nodal price signals; and
c) Load flow-based approaches.

8. While ENA is disappointed that empirical analysis has indicated that such approaches would not be practical or generate more efficient location decisions, what is more disappointing is that the issue has morphed back into a debate about who pays for the HVDC?

9. In ENA's view, while it is important that genuine material inefficiencies are addressed by regulators, it is important that rent-shifting activities, dressed up as efficiency concerns do not define the Authority's on-going work-programme. Our hope is that this exercise will be the last time that the Authority revisits HVDC charges and, in particular, all necessary analysis is done to establish a robust, enduring solution.

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1 Electricity Commission (2009) *Consultation Paper. Transmission Pricing Review: High Level Options*

10. Overall, ENA is surprised that there is a majority view that the small quantum of efficiency benefits identified is sufficient to justify a significant change to the incidence of HVDC charges. The quantified benefits of moving from a more efficient charging approach ($/MWh injected in the South Island) to shifting the HVDC charge on to consumers are estimated to be between $7-$39 million net present value ("NPV") over thirty years. By way of contrast, we estimate[2] that the NPV of increased charges to consumers of a changed incidence of HVDC charges could be up to $1.2 billion over 30 years, and even under a transition arrangement, consumers would ultimately become liable for more than $100 million in HVDC charges per annum.[3] In an electricity market that appears beset with concerns about generator market power, ENA heavily discounts the likelihood that any minor improvement in the efficiency of the wholesale market would translate to lower prices to consumers.

Analysis framework

11. HVDC pricing has been a long-running issue from the time of its inception. South Island generators have mounted a well-resourced campaign to shift the incidence of charges from South Island generators to loads, making various arguments about the identities of beneficiaries of the link and inefficiencies created by the specific methodology used to apportion charges between the South Island generators.

12. In 2004, the Electricity Commission ("Commission") published *Guidelines for Transpower's Transmission Pricing Methodology*. These guidelines were challenged in the High Court, which directed the Commission to reconsult on and reconsider the Guidelines in respect of HVDC charges. In particular, the Commission was required to consider the history of charging, including the transitional and disputed nature of the HVDC charges up to that point. In March 2006, the Electricity Commission issued the paper *Explanatory Paper – Commission's Final Decision: HVDC transmission pricing methodology*. That paper concluded that South Island generators should pay for existing and new HVDC assets, having considered the Electricity Commission's statutory objective and the various economic efficiency principles for transmission pricing set out in the Electricity Governance Rules.

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2 Given that we have not been able to identify within TPAG's paper a comparable NPV of HVDC charges that might be levied on off-takes, only $/MWh increases.

3 Based on an assumed change-over in $2013/14, an 8% discount rate and costs set out in footnote 57 of the Discussion Paper.

13. Without repeating the detail of the Electricity Commission's decision, it was very clear that the Commission made a decision that fully contemplated its statutory objective, including numerous components that address economic efficiency (e.g., directly within the statutory objective, as well as within the Rules). While the Authority has a new statutory objective, it is not evident to the ENA that, in respect of the transmission pricing methodology, there is any material difference in the relevant considerations contemplated by the Commission. ENA endorses the Analysis framework and efficiency considerations adopted by TPAG at paragraphs 14 to 21, which are materially the same as those contemplated by the Commission.

14. In the ENA's view, the relevant starting point for analysis is therefore the Electricity Commission's decision, which resolved the debate about beneficiaries of the HVDC link (including Pole 3) and the most appropriate party to pay its costs in light of:

a) the history of the link;
b) the link's overall function in the market; and
c) the efficiency impacts of allocating the costs to different market participants.

15. In light of the importance of regulatory consistency to the overall credibility of the market, ENA submits that there should be substantial inefficiencies created by the current or modified allocation of HVDC charges to South Island generators, before the Authority concludes that there should be a shift in the incidence of charges (this threshold is consistent with the Authority's Code Amendment Principles 2 and 3). If consumers, particularly large consumers who are sensitive to the level of delivered electricity prices, perceive that they may be subject to substantial changes in market arrangements (of which this would clearly be one) for no discernable long-term benefit, then this is likely to undermine investor confidence in downstream markets, to the detriment of New Zealand.

16. The ENA submits that the Authority should therefore adopt the following decision-making framework, which we submit is consistent with the Code Amendment Principles, but provides a clearer framework for the decision:

a) Identify the inefficiencies associated with the status quo HVDC pricing arrangements;
b) Identify within the status quo allocation whether there are modifications that could be made to reduce the extent of any identified inefficiency (e.g., the move from HAMI to MWh charging);
c) Assess the materiality of any remaining inefficiency to determine whether it is material enough to consider a change in the incidence of HVDC charges (e.g., from South Island generators to loads); and

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

17. TPAG has conducted analysis which informs this decision-making framework, but its primary comparisons are between the postage stamp transition and the status quo, and it does not consider to any discernable degree the impact on the overall credibility of the market.

18. ENA submits that the test in the fourth bullet point above is important. The New Zealand electricity market has been highly contentious, with numerous changes in market structure and governance arrangements due to lack of confidence in its ability to deliver sound outcomes to consumers. Energy prices have increased rapidly above the rate of inflation, and there have been repeated allegations of exercise of market power (e.g., Wolak report, recent UTS). Accordingly, there is real risk that downstream investment in the New Zealand economy is impacted by negative perceptions of the integrity of the electricity market. Therefore, it is important that regulatory decisions, whilst recognising the importance of investor confidence, do demonstrably provide benefits to consumers. TPAG has not considered the extent to which the majority view takes into account how a change in incidence of HVDC charging would impact on market credibility. In light of the up to $1.2 billion shift in HVDC charges (NPV over 30 years), this is an important consideration.

Comments on the quantitative analysis

19. ENA has not sought to review the quantitative analysis undertaken through the various groups that have ultimately contributed to the analysis set out in the Discussion Paper. In general, the analysis seems appropriate given the modelling tools available, but we submit that it is important to recognise that the tools are, in spite of their mathematical complexity, still simplified abstractions of reality. In particular, a key assumption by the majority appears to be that there will be some offsetting of higher HVDC charges to consumers with lower wholesale prices in the longer term under the “postage stamp” and “postage stamp transition” options. ENA strongly questions the validity of such an assumption.

20. It appears to be an accepted fact that the New Zealand market is subject to observable periods where market power is exercised by generators either through the use of transmission constraints or in times of tight winter fuel supplies. Inevitably this must translate into higher hedge prices and charges to consumers. The ability to exercise market power is likely to mitigate the impact of HVDC charges on South Island generation investment decisions as prices can be expected to exceed long-run marginal costs. ENA agrees with the minority of

the TPAG which identifies that there are a number of factors that impact on investment decisions (paragraphs 6.5.17-18) of which the HVDC charge is but one small component.

21. The ability to exercise market power also impacts on the extent to which any cost savings to generators are likely to be passed through to consumers. ENA submits that whilst the technical analysis, which most closely resembles a perfectly competitive paradigm of investment decisions, is informative, the imperfectly competitive nature of the market suggests that the projected reduction in prices should be heavily discounted from a long-term consumer benefit perspective.

22. Finally, ENA agrees with TPAG's decision not to investigate the capacity rights approach further. In our view it is likely to further complicate the New Zealand electricity market and carries with it the risk of failing to deliver Transpower's revenue requirement in respect of the HVDC.

23. Nevertheless, if the Authority does ultimately shift the incidence of the HVDC charge to consumers, ENA recommends that consideration be given to an approach whereby, on behalf of consumers, a new market entity is established to operate the link as a merchant inter-connector. The difference in prices between islands would be used to defray some of the cost of the HVDC. This would potentially result in only modest additional complexity to the market, but could mitigate the impact of HVDC charges on consumers. We stress that this is not a fully developed concept, but is worthy of consideration.

Comments on the majority and minority views

24. The majority of the TPAG conclude that (page 76):

- "the efficiency gains are greatest from applying either the postage stamp or postage stamp transition;
- the likelihood of capturing the efficiency gains from either the postage stamp or postage stamp transition is equivalent to the likelihood of capturing the benefits under MWh;
- postage stamping is likely to create an efficiency gain but it results in a significant immediate and certain transfer of value to SI generators offset by future and uncertain wholesale price effects;
- as for postage stamping, the postage stamp transition option is likely to create an efficiency gain, but does not involve immediate wealth transfers. This option has the highest combined net benefit of all the options – it will provide efficiency gains with the least likelihood of dis-benefits to consumers."

25. In contrast, the minority conclude that (page 71) "there is no clear and material efficiency gain to justify a change", with significant uncertainty about the likelihood that the change would bring about the efficiency improvements modelled.

26. Neither the majority nor minority define what they consider to be "material". ENA submits that materiality needs to be set in the context of the overall market. Relative to a $/MWh charge on South Island generation, a shift to postage-stamp pricing would provide additional benefits of $7 to $39 million NPV over thirty years, or $3 million per annum expressed on an annuity basis.[4] In a market of around $7 billion per annum, the estimated additional efficiency benefits do not appear to be "material".

ENA's conclusions

27. Overall, the ENA does not believe that TPAG has identified efficiency gains that are sufficient to warrant a change from the status quo. Even under the postage stamp transition, whereby the majority view proposes an approach which softens the blow on consumers, consumers would face a certain increase in short-term price in exchange for uncertain medium to long-term price reduction.

28. More generally, ENA is doubtful that from the long-term benefit of consumer perspective, there would be increases in efficiency under "postage stamp transition". Ultimately, if the proposals are to the long-term benefit of consumers, rather than serving the interests of generators, we would expect to see this reflected in wide-spread consumer support and endorsement of the proposals. The ENA suggests this is unlikely. While consumers can speak for themselves, it would seem unlikely that this approach would enhance the credibility of the overall electricity market. Consumers, particularly those in price sensitive industries, would potentially view such a change as demonstrating regulatory capture by generators seeking to enhance their commercial positions at the expense of consumers. This would have a negative impact on investment in New Zealand, with consequential impacts on New Zealand's overall well-being.

29. While it is impossible to quantify such macro impacts, as with all cost-benefit analysis it is important to stand back from the numbers and assess the overall

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[4] +$11 to $96 million (post stamp) less + $4 to $57 million (MWh), compared to the status quo.

risks of the approach. In our view, the risks are too great from a consumer perspective.

30. If our recommendation is not accepted, ENA submits that a postage stamp transition approach should be followed, which maximises benefits to consumers. ENA also submits that a transition approach should not be seen as mutually exclusive to a refined allocation methodology within South Island generators (e.g., MWH charging and a transition could be implemented).

31. ENA does not take a strong view on the relative merits of the HAMI approach to charging versus an MWh-based approach, but nevertheless based on the analysis set out in the Discussion Paper, it does appear that the MWh-based approach would reduce potential distortions in peak investments in the South Island. We question the assumption that it would be impossible to find “incentive-free” allocation approaches within South Island generators, and recommend the Authority considers this issue further. Additionally, there may be enhancements of the MWh-based approach which result in further efficiency enhancements, for example, adopting a three-year rolling average to determine charges.

3. Static reactive compensation (“SRC”)

32. TPAG sets out its support for the introduction of a kvar charge and amendments to the Connection Code as follows:

a) Removing the minimum power factor requirement from the Connection Code (Schedule 8 of the Benchmark Agreement) for the UNI and USI regions only, as follows:

“4.4 Minimum power factor

*(a) If **electricity** is being drawn off the **grid**, the Customer must, in the case of demand at Points of Service in the Lower North Island Region and the Lower South Island Region, maintain a Power Factor of not less than 0.95 lagging at each relevant Point of Service during each relevant regional peak demand period.*

(b) For the purposes of this clause:

*(1) the regional peak demand periods and regions are as defined in Schedule F of the **transmission pricing methodology**; and*

(2) the relevant regional peak demand period is the regional peak demand period for the region in which the Point of Service is located.

b) Amending Schedule 12.4 Transmission Pricing Methodology to add the new kvar charge (better termed a *reactive power offtake charge*) and a penalty charge.

8.7.3 The annual reactive power offtake charge would require specification of:

a) The points of service it would apply to, being those in the UNI and USI regions.

b) Its unit of measurement, being net average offtake reactive power per customer in kvar.

c) The time period used for its assessment, being the regional coincident peak demand (RCPD) for a customer at a customer location.

d) The methodology to be used in establishing the annual $/kvar charge rate, based on assessing the replacement capital and operating costs of a grid capacitor bank (or a group of banks of different sizes and voltages).

e) The methodology must be developed to establish the expected reactive power offtake revenue, this revenue to be offset against the interconnection revenue requirement.

8.7.4 The penalty charge would require specification of:

a) The points of service it is to apply to, being those in the UNI and USI regions.
b) The methodology to establish the process of applying and level of the penalty charge to apply when the power factor is less than 0.95 lagging.
c) interconnection revenue requirement would then be reduced by the quantum of the penalty charge applied. "

33. TPAG's recommended approach would remove the current unity power factor requirement and introduce price signals for distributors to consider in evaluating whether to invest in equipment on the distribution network or for Transpower to invest.

34. TPAG explains that such an approach would:

a) be consistent with the beneficiary pays principle;
b) promote locationally efficient investment in SRC equipment;
c) have minimal unintended efficiency consequences;
d) raise no particular competition concerns;
e) have modest implementation costs; and
f) promote good regulatory practice by removing the unity power factor requirement that is currently practically impossible to comply with and which results in complex arrangements to address non-compliance.

35. ENA supports removal of the requirement for unity power factor in the UNI and USI, for the reasons set out in the Discussion Paper.

36. In principle, ENA also supports the proposed introduction of a kvar charge to incentivise efficient investment in SRC. A number of distributors already use such a charging approach to create incentives for their larger connected customers to meet minimum power factor requirements. Typically these charges only apply when power factor falls below 0.95 lagging.

37. While ENA supports the kvar charging concept, ENA questions whether it is necessary to adopt a charge for the range 1.0 to 0.95 lagging. Such a charge is only desirable where there are genuine costs to be avoided or benefits to be achieved. For example, the analysis of the value of increased thermal capacity limits (page 113) applies a rule of thumb value per MW of additional capacity to determine the potential benefits of improved power factor on capacity, but more

relevant is the scale of deferred transmission investments. If power factor makes no discernable impact on the timing of transmission capacity increments then it may not be appropriate to levy charges on relatively good power factor.

38. Implicitly, TPAGs approach appears to assume that investments should be made (or there are costs that are incurred), when power factor does not equate to 1.0 and therefore a charge should apply whenever power factor is below unity. ENA submits that this assumption needs to be tested, as it may lead to inefficient investments in SRC, when power factor may already be at efficient levels.

39. ENA therefore **recommends** that further consideration be given to the ranges where kvar charges apply. For example, it may be most efficient to apply charges only where power factor falls in the range 0.98 to 0.95 lagging and penalty charges when power factor falls below 0.95 lagging. Alternatively, a kvar charge might apply only when power factor falls below 0.95 lagging. The key issue to address is the appropriate threshold where charges apply. The SKM report to the ENA suggest that 0.95 lagging would be an appropriate point, so ENA submits that further work should be undertaken to test or validate this finding.[5]

40. TPAG assumes that the Commerce Commission's regime for non-exempt EDBs would complement the recommended approach. ENA notes that this is not correct. Under the arrangements for "recoverable costs" EDBs may pass through Transpower's transmission charges, which would include any kvar charge (clause 3.1.3(1) (b)). However, if an EDB makes an investment to avoid the kvar charge, this is not treated as a recoverable cost, unless Transpower initially made the investment and then the EDB purchased it from Transpower (clause 3.1.3(1)(e)). Accordingly, the kvar charge would not promote efficient investment by EDBs, because they cannot practically recover the costs of those investments. The Authority should therefore ensure that before any kvar charge is implemented, the Commerce Commission reissues its Input Methodologies to remove this impediment to efficient EDB investment.

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5 Sinclair Knight Merz (2010) *Review of Connection Code : UNI and USI Power Factor Requirements*

4. Options for pricing connection assets

41. Chapter 7 of the Discussion Paper assesses options for pricing connection assets. It does not recommend a particular option but rather concludes (paragraph 7.7.3):

> *The TPAG has not reached a firm conclusion on whether these potential benefits justify a change from the status quo because further analysis of the efficiency gains and assessment of alternative options requires close coordination with the Commerce Commission. It has not considered whether the status quo arrangements are a regulatory or market failure.*

42. The ENA supports the TPAG conclusion that the pricing methodology for connection assets needs to be designed in coordination with the Commerce Commission's work on transmission alternatives. Furthermore, this pricing methodology needs to be designed with a clear understanding of the relevant shortcomings in the current price/quality regulation arrangements applying to EDBs and the incentive effects on EDBs that arise from these arrangements.

43. We consider any further work on pricing connection assets should be scoped to take account of the transmission alternatives regime emerging in the Commerce Commission's Input Methodology process, and also inform improvements to how transmission services are handled in the price/quality regulation applying to EDBs. We explain why below.

Pricing to encourage reduction in peak demand

44. There are broadly two ways to minimise additional investment in services delivered by connection assets; the first is by reducing peak demand by way of demand side management or locating generation closer to load, the second by providing the services in the most cost effective manner.

45. The first category (pricing to encourage reduction in peak demand) requires a pricing methodology that reflects the long run marginal costs (LRMC) of providing capacity increments in the service, in order to provide purchasers of the services the appropriate signals as to the extent to which they should take other actions (e.g. undertake DSM or locate generation closer to load). In this submission ENA does not express a view on whether there should be changes to the current method of identifying and pricing connection assets, leaving individual ENA Members to address the issues associated with the different approaches (e.g., load flow, 'but for' approaches). From the ENA's perspective, the key issue is that for any price signals to have economic effect, the purchasers of the transmission service need to be able to capture some of the benefit of lowering transmission costs by either competing to provide a substitute service, or managing demands to avoid the need for further investment.

46. EDBs are the dominant purchasers of (off-take) transmission and under the current price/quality regulatory arrangements they have very limited incentives to lower transmission charges as any such benefits (with a few exceptions) must be "passed-through" to their customers.

47. Thus it is possible in the current environment for the EA to design a more elaborate pricing methodology for connection assets (e.g. using a "but for" or flow-tracing approach as outlined in the Discussion Paper) but which in practice will have no effect due to the absence of incentives on EDBs to respond to such pricing signals. In order to achieve effective pricing of connection assets it is critical this wider context is considered. Ideally the EA's work on the pricing of connection assets would inform work by the Commerce Commission on improving the manner in which transmission services are handled in the price/quality regulation applying to EDBs.

Transmission alternatives

48. The Discussion Paper recognises that assessment of expected net benefits from adopting some form of "but for' or flow-tracing approach to pricing connection assets requires knowing the likely effectiveness of the transmission alternatives regime (paragraphs 7.7.6 & 7.7 8). The transmission alternatives regime is part of the draft Commerce Commission's Capex Input Methodology for Transpower.[6]

49. The ENA supports this view, as the design of the transmission alternatives regime will determine what residual role the pricing of connection assets has to play as part of any assessment of potential substitutes to transmission services.

Summary

50. The ENA supports the Discussion Paper's conclusion that an assessment of potential pricing methodologies for connection assets requires knowing the likely effectiveness of the transmission alternatives regime (which is currently in draft as a ComCom IM). Further, such assessment also needs to be informed by a clear understanding of the incentive effects on EDBs related to transmission services that arise from price/quality regulation applying to EDBs.

51. Ideally the Authority's work on the pricing of connection assets should inform improvements as to how transmission services are handled under price/quality regulation. Such a work programme would require coordination between the Authority and the Commerce Commission and probably some form of joint

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6 See paragraph X52 of *Capital Expenditure Input Methodology (Transpower) Draft Reasons Paper* July 2011, Commerce Commission

project. We consider a coordinated approach across these two issues (and which also takes into account the emerging transmission alternatives regime) a prerequisite to making sustainable progress on each.