From the Electricity Networks Association

Submission on Transmission Pricing Methodology: Beneficiaries-pay options

25 March 2014

The Electricity Networks Association makes this submission along with the explicit support of its members listed below.

Alpine Energy Ltd

Aurora Energy Ltd

Buller Electricity Ltd

Centralines Ltd

Counties Power Ltd

Eastland Network Ltd

Electra Ltd

E A Networks Ltd

Electricity Invercargill Ltd

Horizon Energy Distribution Ltd

Mainpower NZ Ltd

Marlborough Lines Ltd

Nelson Electricity Ltd

Network Tasman Ltd

Network Waitaki Ltd

Northpower Ltd

Orion New Zealand Ltd

OtagoNet Joint Venture

Powerco Ltd

Scanpower Ltd

The Lines Company Ltd

The Power Company Ltd

Top Energy Ltd

Unison Networks Ltd

Vector Ltd

Waipa Networks Ltd

WEL Networks Ltd

Wellington Electricity Lines Ltd

Westpower Ltd

Contents

Appendices

Executive summary

1. The ENA is pleased that the Authority is reconsidering aspects of its proposed transmission pricing methodology (TPM) design. However, we are disappointed by the limited nature of this reconsideration.

2. The Working Paper does not engage with the fundamental issues raised in submissions as to whether the very substantial costs to implement any of the beneficiaries-pay options are warranted. Rather, it relies on the Authority's Economic and Decision-making Framework (Framework) to assume that a beneficiaries-pays approach will be superior to other options on the basis that other options higher up in the Framework's hierarchy have been dismissed. Using the Framework in this way does not assist sound economic assessment of feasible options.

3. The ENA encourages the Authority to step back from what has become a focus on the beneficiaries-pay approach and consider other conventional ways of comparing and assessing the design of transmission pricing options. The six "efficiency considerations" employed by the Transmission Pricing Advisory Group in its assessment of TPM options is a useful example of assessment criteria the Authority should consider employing.

4. The ENA considers the benefits and costs of the proposed beneficiaries-pay methods need to be re-assessed on a comparable basis with "alternative charging options", and without according the beneficiaries-pay arrangement any assumed advantage.

5. We comment in section 3 on each of the four options presented in the Working Paper and provide responses in the appendix to each of the detailed points used in the Working Paper to assess each option. None of these options address fundamental points raised by the ENA or others on the 2012 TPM Proposal as regards the following:

   - No linkages have been identified between the proposed new transmission price signals and market participants' incentives (in the absence of mechanisms to capture private benefits) and ability to improve transmission investment decision-making.
   - The TPM Proposal would introduce into the wholesale electricity market price signals that bear no relationship to the transmission costs that the bids and offers in that market give rise to. Thus these price signals can be expected to result in a less efficient rather than more efficient energy market.
   - The TPM Proposal would be very susceptible to lobbying, and therefore be unstable, in that it would be a complex creature of regulation with many elements on which the Authority or Transpower would be required to exercise their judgement and by implication elements which market participants would persistently attempt to influence.
   - The SPD charges would create incentives for generators to adopt bid strategies in the wholesale market akin to pay-as-offered strategies, with the associated distortions that the Authority has already concluded are not in the long-term interests of consumers.

- The SPD charges would disadvantage areas where there has been historically under-investment in transmission relative to demand growth.
- Those participants that use electricity principally in the peaks would be advantaged.
- The SPD method relies on a counter-factual (when removing transmission links to identify private benefit) that takes little account of how market participants would in practice reconfigure their activities in the absence of such transmission links, and therefore is a very incomplete measure of the incremental benefit that the transmission links give rise to.

6. The Working Paper provides a preliminary view that each of the four options considered would result in net benefits relative to the status quo and therefore should be included in the next stage of development. However, the qualitative assessment of each option identifies costs and benefits for each, and thus to establish if each of them would provide net benefits requires estimating the relative quantum of benefits and costs of each (i.e. it is an empirical issue) The Working Paper provides no such estimates (and does not attempt to rank the costs and benefits), resulting in the absence of analytical support for these preliminary views.

7. This absence of analytical support for the preliminary views in the Working Paper is an important gap in the logic of the Working Paper, as these preliminary views are used as the basis to propose that the four options should be carried forward to the next stage of developing a revised TPM. In effect the Working Paper proposes these options should be carried forward because it is assumed they would provide net benefits, not because it has been demonstrated that they would.

8. It appears the key attraction to the Authority of the beneficiaries-pay approach is that market participants would face interconnection transmission charges in proportion to the extent to which they are perceived to benefit from this service, and not more than their private benefit from this service. This approach results in a particular form of allocation of the fixed costs of supplying the interconnection transmission service. The Authority considers this distribution of charges would lead to the various benefits listed in the assessments of each option in the Working Paper (e.g. more engagement in investment decision-making and thereby more efficient outcomes, reduction in deadweight losses, etc.).

9. The ENA suggests the Authority should consider approaches other than beneficiaries-pay in its review of the TPM. However, if it is unwilling to do so, it may be possible to achieve a distribution of interconnection charges that reflects (at least in part) the Authority's beneficiaries-pay approach, but which requires only modest changes to the status quo and modest implementation costs, which does not introduce distortions into the energy market and which results in stable (within year) transmission prices. We suggest below one way in which this could be designed (while recognising there are a range of possibilities).

10. This suggestion should not be interpreted in any way as the ENA's preferred approach to a TPM, as it is not. It is made on a without prejudice basis to our concerns set out in section 2 & 3 of this paper in relation to the beneficiaries-pay options in the Working Paper, and to the ENA remaining unconvinced of the claimed efficiency benefits from a beneficiaries-pay approach. The ENA's suggested approach would focus on the following ordering of interconnection charges to provide long run marginal cost (LRMC) price signals to the extent possible, and using beneficiaries-pay or RCPD/I charges (or some combination) to recover any residual interconnection revenue requirement. This could be achieved in the following way:

- Develop estimates of the LRMC of incremental capacity for the interconnection transmission service. The objective of this set of charges would be to enhance dynamic efficiency by signalling to transmission users the LRMC of their choices to demand additional interconnection capacity at peak periods. It is likely LRMC would be best estimated in terms of transmission regions as opposed to individual GXPs.
- The LRMC charge would be levied on those able to respond to it over extended periods of time (as it is this response that provides the dynamic efficiency benefits). Our initial view is that it should include both injection and offtake GXP customers, but the efficiency effects of including injection GXPs would need to be tested.
- Use a beneficiaries-pay charge, or an RCPD/I charge, or some combination of these two charges, to collect any residual interconnection revenue requirement. The relative weighting on each of these charges, and the parties that would face these charges, would need to be determined by further analysis as to their relative efficiency effects (net of implementation and transactions costs).
- For transaction cost reasons all interconnection charges would be levied at the GXP. This would include (where relevant) charging generators at injection GXPs and direct connect customers at their GXPs. For off-take GXPs further analysis would be required to determine the relative efficiency (net of transaction costs) of levying the charges on distributors or retailers.
- In all cases the interconnection charge would be set in advance of the pricing year to which it applies and be held steady within the year, using a similar pricing timetable to that currently used by Transpower. This would mean no disruption to the existing Part 4 pricing cycles for Transpower, or the way in which transmission charges are handled in the Part 4 price control and information disclosure regimes applying to electricity distributors.

11. An important component of the above approach would be to reconsider the introduction of a charge that approximates the LRMC of transmission capacity. The Authority recognised the desirability of a LRMC charge in its 2012 TPM Proposal and in the Working Paper but has not taken it further due to perceived complexities and the assumption that beneficiaries-pay based charges are superior to administrative-based charges (on the basis that the former is higher up the Authority's Decision-Making Framework hierarchy). Neither of these views is supported by analysis in the Working Paper.

12. The Authority's objections to LRMC charges in the Working Paper (and in its 2012 Framework paper) are in the nature of assumptions and many of the 'issues' identified in relation to an LRMC charge apply also to SPD-based charges, but in the latter case they are not considered insurmountable. For example:

- Both a LRMC charge and the SPD method need to be estimated administratively and levied on those using interconnection services (i.e. without requiring capacity rights).

- Both require judgements as to how the complexities of the meshed nature of the grid is simplified for the purpose of deriving the requisite estimates.
- Both require some form of residual charge to allow Transpower to recover its maximum allowable revenue.

13. An LRMC charge could address many of the concerns with the options in the Working Paper (see our appendix for detail) as well as those raised by the Authority in relation to avoided cost of transmission payments (ACOT) in its recent paper on that topic. By placing an LRMC price into the transmission market, parties could make efficient choices about whether to consume interconnection services or not, to shift load to off-peak periods, or to invest in alternatives irrespective of whether the "exacerbators" are identified by the Authority in its Framework. Such a LRMC price signal would have desirable dynamic efficiency implications that the Authority has already recognised.

14. The ENA submits that the Authority needs to reconsider its view on a LRMC based interconnection charge, and the possible design and use of RCPD/I charges, along with beneficiaries-pay options, and assess these various possibilities on their economic merits, rather than only on how they are perceived to fall in the hierarchy of the Authority's Framework.

1. Introduction

15. The Electricity Networks Association (ENA) appreciates the opportunity to submit on the Electricity Authority's (Authority's) working paper "Transmission Pricing Methodology: Beneficiaries-pay options Working Paper" (Working Paper).

16. The ENA is pleased that the Authority is re-considering in its Working Paper series some aspects of its proposed TPM design as set out in its 2012 TPM Proposal.[1] However, we encourage the Authority to consider wider possibilities than those in this Working Paper as we do not consider the options presented address adequately the shortcomings that have been identified with this approach. The review of the TPM appears to have got stuck on only beneficiaries-pay options and in section 2 we discuss the importance of considering a wider set of options. In section 3 we comment on the options presented in the Working Paper and in section 4 we suggest an alternative way to incorporate a beneficiaries-pay component into the TPM. The Appendix provides detailed comments on the assessment of the costs and benefits of each option presented in the Working Paper.

17. The ENA's contact person for this submission is:

Nathan Strong

Chair, ENA Regulatory Working Group

Email: nathan.strong@unison.co.nz

Tel: 021 566 858 or 06 873 9406

[1] Electricity Authority, *Transmission Pricing Methodology: issues and proposal*, 10 October 2012.

2. Policy options have become stuck on beneficiaries-pay

18. This Working Paper (and the Working Paper series on the TPM) is in response to widespread concerns from the sector that the 2012 TPM Proposal would be inconsistent with the Authority's statutory objective, that is it would impede rather than promote economically efficient decision-making. Unfortunately the Working Paper does not engage with many of the substantive TPM design issues raised by submitters.

19. In our submission on the TPM Proposal the ENA pointed out that:

- No linkages have been identified between the proposed new transmission price signals and market participants' incentives (in the absence of mechanisms to capture private benefits) and ability to improve transmission investment decision-making. In the absence of these linkages we were unconvinced of the claimed benefits the proposal would have on transmission investment decision-making. These linkages have not been identified in the Working Paper.
- The TPM Proposal would introduce into the wholesale electricity market price signals that bear no relationship to the transmission costs that the bids and offers in that market give rise to. Thus these price signals can be expected to result in a less efficient rather than more efficient energy market. This unattractive feature is retained in all the options in the Working Paper.
- The TPM Proposal would be very susceptible to lobbying, and therefore be unstable, in that it would be a complex creature of regulation with many elements on which the Authority or Transpower would be required to exercise their judgement and by implication elements which market participants would attempt to influence. Thus we were not convinced of the benefits claimed for it from an expectation that it will be durable. The strong negative feedback from the sector on the 2012 TPM Proposal has reinforced its likely instability. While the options in the Working Paper would remove some of the complexity of the original design they remain vulnerable to a high degree of lobbying in their detailed design and implementation. The Working Paper asserts the options would be more durable than the status quo without explaining how or why.

20. Other submitters raised the following issues that are not addressed in the Working Paper:

- The SPD charges would create incentives for generators to adopt bid strategies in the wholesale market akin to pay-as-offered strategies[2], with the associated distortions that the Authority has already concluded are not in the long-term interests of consumers.[3]

---

2 For example, Baringa for TrustPower Ltd, p.44

3 Layton, Brent, 2013, *The Economics of Electricity*, Electricity Authority, 4 June, paragraphs 9, 10, 11 and 15 explains the economic problems with a pay-as-offered market for electricity in the New Zealand context.

- The SPD charges would disadvantage areas where there has been under-investment in transmission relative to demand growth.[4]
- Those participants that use electricity principally in the peaks would be advantaged.[5]
- The SPD model method relies on a counter-factual (when removing transmission links to identify private benefit) that takes little account of how market participants would in practice reconfigure their activities in the absence of such transmission links, and therefore is a very incomplete measure of the incremental benefit that the transmission link gives rise to.[6]

21. In the absence of these issues being addressed, the Working Paper does not engage with the fundamental issue of whether the very substantial costs to implement any of these options are warranted.

22. Many of the above issues challenge the view that a beneficiaries-pays approach will deliver net benefits. The Working Paper does not engage with those challenges. Rather, it relies on the Authority's Economic and Decision-making Framework to assume that a beneficiaries-pays approach will be superior to other options on the basis that other options higher up in the Framework's hierarchy have been dismissed. Using the Framework in this way does not assist sound economic assessment of feasible options.

23. We encourage the Authority to step back from what has become a focus on the beneficiaries-pay approach and consider other conventional ways of comparing and assessing the design of transmission pricing options. The six "efficiency considerations" employed by TPAG in its assessment of TPM options is a useful example of assessment criteria the Authority should consider employing.[7]

Consideration	Brief description
Beneficiary Pays	Apply transmission costs to particular beneficiaries where it is practical to identify them and when that application leads to net benefits.
Location price signalling	Provide additional locational price signals only where they promote more efficient use of the network and investment in transmission, generation and DSM.
Unintended efficiency impacts	Seek efficiency gains by avoiding incentives that could undermine the efficient use of the network and investment in transmission, generation and DSM.

4 For example, Marsden Jacob Associates for Vector Ltd p.24

5 For example, Vector Ltd submission, paragraph 84

6 For example, Powerco Ltd submission p.13

7 Transmission Pricing Advisory Group, 2011, *Transmission Pricing Analysis: Report to the Electricity Authority*, 31 August, Table 1

Competitive neutrality	Provide a level playing field for long-term competition in generation and retail.
Implementation and operating costs	Take account of implementation, transition and operating costs.
Good regulatory practice	Adopt a consistent and durable approach that is compatible with market arrangements and avoids wealth transfers unless they are clearly justified by efficiency benefits.

3. Comment on options

24. In Appendix 1 we comment on each of the points raised in the Working Paper's assessment of the costs and benefits of the four options. From that analysis, using the description of costs and benefits from the Working Paper, it is not possible to conclude qualitatively whether or not each option would provide net benefits relative to the status quo, as most issues are perceived to have both a potential benefit and cost, resulting in the net position needing to be determined empirically. The Working Paper does not attempt to rank the costs and benefits. Thus it is not clear how the Authority comes to a preliminary view that each of the options would likely result in net benefits relative to the status quo.

25. We also note that there is little consideration in the Working Paper of how the transmission prices would interact with other aspects of pricing for electricity. ENA submits that transmission pricing should recognise these linkages with other elements of market pricing (such as energy, FTRs and connection contracts).[8]

26. We comment below on key aspects of each option.

3.1 Option 1: Simplified SPD charge

27. Option 1 is little different to the October TPM Proposal at a fundamental level, in so far as it is based on the same modelling approach, and no account appears to have been taken of the issues raised in section 2 above. The ENA's concerns with the SPD method remains as summarised in section 2.

28. It is the ENA's view that the Authority has not presented strong arguments or adequate explanation of many aspects of the design of its proposals including:

- The practical implications of changes in the market shares of retailers, including entry and exit, where charges are based on the previous three years.
- How the objectives of cost recovery and reflection of benefits are weighted relative to each other. For example using gross benefit (rather than net) overstates the value (benefit) to users and is inconsistent with the way investment decisions are made, nonetheless it is described as 'superior' because it is considered less costly to implement and yields more revenue (albeit inefficiently). As highlighted in paragraph 24 it is not clear how the view that it is superior can be reached qualitatively. Conversely the capping proposals limit the benefit that is measured and recover less of the cost (potentially) and there is only a limited, largely subjective discussion of these effects.
- The assumptions around the value of lost load and demand response appear largely arbitrary and would result in variations in charging with no clear objective argument about which result is better.

---

[8] This was an explicit requirement in Part F Section IV Rule 2.6 of the Electricity Governance Rules and clauses 12.79 of the Code prior to 1 June 2011.

- The Authority notes that several of its proposals could yield behavioural changes but there is a lack of clarity about what changes are desirable and why (or why not). In general the Authority appears to assume that behavioural response to prices is undesirable without considering that correctly set prices will elicit efficient responses, for example a shorter capping period is (counterintuitively) suggested to have the benefit that it *reduces* the incentive to avoid peaky transmission use.
- It is not clear whether the Authority has considered the design elements in combination, for example how is the appropriate choice of capping period influenced by the length of the averaging period.
- How the design choices will affect the residual charge is not addressed, for example the choice of net/gross injection or charging at a substation.

29. Fundamentally, all the options the Authority presents are based on the same model and suffer the same issues to a greater or lesser extent. In the rest of this section we comment on the additional features in the other options presented in the Working Paper.

3.2 Option 2 (a): GIT-plus-SPD

30. The GIT plus SPD option would recover the total amount of revenue associated with an asset from the load at the GXPs that were deemed (in a way yet to be clarified) to be the beneficiaries of the "main function" of the asset. Since reliability investments are not required to yield a net market benefit (in terms of the Commerce Commission's criteria for approving the investment) *and* the group of beneficiaries excludes those who enjoy secondary benefits, or non-reliability benefits, it is probable that this method would result in a charge to the so-called beneficiaries of a reliability investment that exceeds their private benefit.

31. For example, the Electricity Commission determined that the identifiable benefits of the NAaN investment were less than the costs but approved it anyway. The Commission's decision approved the NAaN on the basis that it was $34 m cheaper than the next best alternative, despite an expected net market cost of $240 m.[9] Charging the full cost of the NAaN to the identified beneficiaries in Auckland/Northland would violate the Authority's principle that parties should pay no more than their private benefit.

32. The Authority describes its rationale for this approach as "the intention with the GIT-based charge is to ensure that incentives to promote an investment are aligned with willingness to pay for it. This should help promote efficient investment." (paragraph 8.12) This approach is inconsistent with the test for approving reliability investments, which is to identify the least cost method of meeting a particular reliability standard (eg. N-1).[10]

---

9 Electricity Commission, 2009, *Final decision on proposal one in Transpower's North Auckland and Northland Investment Proposal*, 30 April, Table 6.1

10 Commerce Commission *Transpower Capital Expenditure Input Methodology Determination*, 2012 Schedule D: Major Capex – Investment Test D1(1)(b).

33. A second concern with the GIT component of option 2(a) is the static nature of the 'areas of benefit' in the GIT charging option (which the Working paper also recognises as a shortcoming). There is no proposed mechanism whereby the GXPs that are deemed to be the beneficiaries at the time of investment approval can change as the usage of the grid evolves, even though patterns of consumption and generation may change materially over the life of the asset.

34. Finally, the use of a consumption-based charge (rather than a demand-based charge) means that the charge bears little relationship to the way in which transmission costs scale over the medium to long term, that is with respect to capacity.

3.3 Option 2 (b): SPD-plus-GIT

35. The GIT component of Option 2 (b) has similar drawbacks to the GIT component just described. It may be an improvement as some of the 'other' beneficiaries are captured through the SPD approach, but it appears this approach would result in double-counting (through the SPD method) some of the benefits to those deemed to be the beneficiaries of the "main function" of the investment under the GIT component. The Authority notes that this double counting may be mitigated as "the SPD method *may not* fully capture the benefits of transmission investments designed to reduce expected unserved energy" (paragraph 9.2, emphasis added). It does not provide an explanation of the circumstances in which this may occur or how significant the issue is.

36. The GIT component in this option is a method for allocating the residual (from the SPD method), and as such it should be compared with other potential methods for allocating the residual charges (e.g. the RCPD/I method) but the assessment does not include this comparison.

3.4 Option 3: Zonal SPD

37. The Zonal SPD option results in a very different pattern of charging from the other options presented. However, it is also based on a very different set of assets (all assets, rather than a small group selected on the basis of size and age in the other options). Thus it is not clear the extent to which the differences in allocations are driven by the method or the differing asset base; this asset base issues needs to be aligned across the various options in order for a comparison of them to be made.

38. The Authority acknowledges that the within-zone charge could be allocated in different ways. This is also true of the cost of the zonal interconnectors, and the ENA recommends that consideration of how to allocate these costs should be extended to include LRMC measures. In this context it may be possible to base the 'increments' on something other than customers, for example on nodes or GXPs.

39. Again the Authority has chosen in this option to use consumption as the charging variable despite the fact that this is not the underlying cost driver of transmission. This approach is described as simple, but it is hard to imagine a capacity based charging regime being that complex (and certainly not as complex as the SPD method).

4. Suggested possible charging structure

40. The Authority appears to be convinced that some form of beneficiaries-pay approach to the TPM would improve the efficiency of the system. As we noted in section 2, and in our submission on the 2012 TPM Proposal, the ENA strongly submits that the Authority should reconsider this view.

> *[W]here a move to "beneficiaries pays" does not bring with it the normal market disciplines associated with it, or strengthen the ability of the beneficiary to influence service delivery in any substantial way, the benefits from such a move need to be identified and assessed relative to other administrative arrangements for charging for this service. In this context there is no reason in principle to favour a "beneficiaries pays" approach over the category of "alternative charging options". The ENA suggests the benefits and costs of the proposed SPD-based method need to be re-assessed on a comparable basis with "alternative charging options", and without according the "beneficiary pays" arrangement any assumed advantage.*[11]

41. It appears the key attraction to the Authority of the beneficiaries-pay approach is that market participants would face interconnection transmission charges in proportion to the extent to which they are perceived to benefit from this service, and not more than their private benefit from this service. This approach results in a particular form of allocation of the fixed costs of supplying the interconnection transmission service. The Authority considers this distribution of charges would lead to the various benefits listed in the assessments of each option in the Working Paper (e.g. more engagement in investment decision-making and thereby more efficient outcomes, reduction in deadweight losses, etc.).

42. The ENA considers the Authority should be considering approaches other than beneficiaries-pay in its review of the TPM. However, if it is unwilling to do so, it may be possible to achieve a distribution of interconnection charges that reflects (at least in part) the Authority's beneficiaries-pay approach, but which requires only modest changes to the status quo and modest implementation costs, which does not introduce distortions into the energy market and which results in stable (within year) transmission prices. We suggest below one way in which this could be designed (while recognising there are a range of possibilities).

43. This suggestion should *not* be interpreted in any way as the ENA's preferred approach to a TPM, as it is not, and it is made on a without prejudice basis to our concerns set out in section 2 & 3 in relation to the beneficiaries-pay options in the Working Paper, and to the ENA remaining unconvinced of the claimed efficiency benefits from a beneficiaries-pay approach.

---

[11] ENA submission on 2012 TPM Proposal, paragraphs 44-45

4.1 Suggested ordering of charges

44. The ENA's suggested approach would focus on the following ordering of interconnection charges in order to provide LRMC price signals to the extent possible, and using beneficiaries-pay or RCPD/I[12] charges (or some combination) to recover any residual interconnection (IC) revenue requirement. This could be achieved in the following way:

- Develop estimates of the LRMC of incremental capacity for the interconnection transmission service. The objective of this set of charges would be to enhance dynamic efficiency by signalling to transmission users the LRMC of their choices to demand additional interconnection capacity at peak periods. It is likely LRMC would be best estimated in terms of transmission regions as opposed to individual GXPs.
- The LRMC charge would be levied on those able to respond to it over extended periods of time (as it is this response that provides the dynamic efficiency benefits). Our initial view is that it should include both injection and offtake GXP customers, but the efficiency effects of including injection GXPs would need to be tested.
- Use a beneficiaries-pay charge, or an RCPD/I charge, or some combination of these two charges, to collect any residual interconnection revenue requirement. The relative weighting on each of these charges, and the parties that would face these charges, would need to be determined by further analysis as to their relative efficiency effects (net of implementation and transactions costs).
- For transaction cost reasons all interconnection charges would be levied at the GXP. This would include (where relevant) charging generators at injection GXPs and direct connect customers at their GXPs. For off-take GXPs further analysis would be required to determine the relative efficiency (net of transaction costs) of levying the charges on distributors or retailers.
- In all cases the interconnection charge would be set in advance of the pricing year to which it applies and be held steady within the year, using a similar pricing timetable to that currently used by Transpower. This would mean no disruption to the existing Part 4 pricing cycles for Transpower, or the way in which transmission charges are handled in the Part 4 price control and information disclosure regimes applying to electricity distributors.

4.2 Comment on possible LRMC charge

45. We wish to comment on a possible LMRC charge as this approach has been recognised by the Authority as desirable and dropped, too early in our view, due to perceived implementation difficulties.

---

[12] Regional Coincident Peak Demand/Injection

46. An LRMC charge would provide transmission users with price signals that approximate the long run costs of their transmission usage at peak times. This is desirable from a dynamic efficiency perspective to inform transmission users' (including consumers') decisions on their usage of the transmission system and their investment in alternatives (including for example in distributed generation). A LRMC charge could address many of the concerns with the options presented in the Working Paper as well as a number of the concerns the Authority raised in relation to ACOT (avoided costs of transmission) payments in its recent paper on that topic.[13]

47. We note in the appendix to this report that many of the inefficiencies and costs associated with the options currently being considered arise because the charges would not approximate LRMC.

48. The Working Paper recognises the desirability of LRMC charges (paragraphs 5.5 to 5.14) and that a beneficiaries-pay approach is inferior, as follows (paragraph 5.13):

> *The Authority acknowledges that setting prices according to incremental benefit at best only approximates efficient signals since prices are unlikely to reflect LRMC. However, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency.*

49. Thus it appears the Authority has not proposed a LRMC charge on the basis that it is too difficult to implement. It mentions the meshed nature of the grid as an impediment "to use mechanisms such as capacity rights or contracts to establish prices based on LRMC for the interconnected grid" (paragraph 5.10). However, an LRMC charge could be estimated administratively (as indeed the SPD method would be) and levied on those using the interconnection service (in the absence of capacity rights), so it is not clear why the absence of capacity rights precludes consideration of a LRMC charge.

50. The ENA recognises estimating the LRMC for the interconnection service is not straightforward and would involve judgments arising from the meshed nature of the system. However, judgments are also required to implement the proposed SPD method in that the order in which assets are removed to complete the SPD "solves" affects the results.[14] Thus the challenges of a meshed grid arise for both methods and it is not clear why the Authority perceives the LRMC method insurmountable but the SPD method not so.

51. In telecommunications regulation there is a well-established Total Service Long Run Incremental Cost (TSLRIC)[15] method for estimating the incremental costs of supplying

---

13 Electricity Authority, *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation; Working paper,* 19 November 2013

14 Powerco's submission to the 2012 TPM Proposal describes a number of examples of the scope for disputes (i.e. judgments) under the SPD method including: "as the solution of "but for asset A" plus "but for asset B" plus "but for asset C" will not necessarily equal the solution of "but for A+B+C" we would expect to see many disputes about the definitions of assets and their treatment by the SPD method." (p.3)

15 Sometimes referred to as Total Element Long Run Incremental Cost, or TELRIC

a defined service in the context of a multi-product business.[16] The Commerce Commission is currently applying this method to estimate the costs to Chorus Ltd of supplying unbundled copper loop and unbundled bit-stream access. The ENA considers this method would provide insights relevant to estimating the LRMC for interconnection capacity.

52. The Working Paper acknowledges (paragraph 5.18) that it would be possible to apply TSLRIC to transmission to identify the incremental change required to supply a particular customer. However, it then goes on to summarily dismiss further consideration of this approach because of modelling and other implementation difficulties that appear no more complex than those arising with the SPD approach:

> *However, the significant economies of scale involved in transmission investment and the need to deal with loop flows in transmission design mean it is likely to be impracticable to apply this approach to non-connection assets in New Zealand. In addition, a methodology (or method) would have to be identified or developed to model the increments to the transmission network required to service transmission customers. Accordingly, the Authority is not proposing to develop this option further. (Paragraph 5.19)*

53. The ENA encourages the Authority to explore possible ways of estimating LRMC for the interconnection service and publish the results, as it has done with the SPD method. This approach would improve transparency as to their relative strengths and weaknesses; at present there is no visibility over whether the Authority has seriously explored a LRMC approach. We note a charge that approximates LRMC over extended periods of time (it need not be perfect) is likely to be more efficient than no such charge, or one that reflects some other economic concept (such as the level of private benefit).

54. The Authority briefly discussed possible LRMC and LRIC options in its 2012 Framework Paper[17] in relation to 'exacerbator pays' options and noted the efficiency benefits of LRMC-based charges:

> *This provides them with incentives to consider alternatives, such as connecting elsewhere, managing their load, investing in their own generation (if they are a load) or undertaking the investment themselves. By charging LRMC, exacerbators can compare this against the cost of alternatives and incorporate this into their decision on whether to proceed with the exacerbating action or inaction. (paragraph 4.5.19)*

55. The 2012 Framework Paper identifies five options for pricing methodologies under exacerbator pays (including the kvar charge). The remaining four options were: two variations on LRIC (one involving a contract, one not), a 'tilted postage stamp' based

---

[16] The method used to identify incremental costs for a defined service in a multi-product business is similar in economic terms to that required to identify separately the incremental costs of incremental transmission capacity from the fixed costs of the service already in place.

[17] Electricity Authority, 2012, *Decision-making and Economic Framework for Transmission Pricing Methodology Review*, 26 January.

on the LRMC of expanding grid capacity in a region, and a peak charge based on LRMC. These options are all worthy of further consideration and as they are higher on the Authority's Framework hierarchy, when using that Framework they should be given priority over beneficiaries-pay options.

56. The Authority did not include LRMC or exacerbator pay options in the October TPM (it included market, market-like, beneficiaries-pay and alternative options but no exacerbator pay options). It is not clearly stated why not, but an exacerbator pay option is proposed for the static reactive support charges (the kvar charge) on the basis that "there are clearly identifiable parties that, by their actions or inaction, cause…requiring investment…" (paragraph 5.2.7). From this we infer the Authority did not pursue exacerbator pays options on the basis that it could not clearly identify the exacerbators. However, the rationale for charging LRMC is that by putting an efficient price into the market, parties can make efficient choices about whether to consume or not, to shift load to off peak periods, or whether to invest in alternatives (e.g. in DG). This desirable response will occur irrespective of whether the exacerbators are identified as such in the Authority's Framework.

57. The 2012 Framework Paper recognises "it would be important to ensure that the [LRMC] charge would be passed on in a manner that provided a price signal so that exacerbators faced the cost of their exacerbating activity". This suggests that a demand-based charge should be structured as a capacity charge, preferably for peak periods, as that would best reflect the usage that drives the need for incremental transmission capacity.

58. Lastly, the 2012 Framework Paper notes that "the revenue from charging exacerbators may be less than the full costs". This point is reiterated in the Working Paper. The ENA recognises that this would be the case, as LRMC can be expected to be lower than average total costs due to the relatively large fixed costs (that don't scale with capacity) of establishing the transmission grid. This suggests that a residual charge would be required, as is the case in most of the options that the Authority is currently considering. Thus an LRMC charge should not be discarded for this reason.

Appendix 1 : Comment on Working Paper assessment of options

EA Assessment	Comment	No.
Assessment of costs and benefits of the simplified SPD charge		
7.115 The benefits of the simplified SPD charge are it would promote:		
(a) efficient transmission investment by increasing the transparency of the benefit parties obtain from transmission assets, and by placing stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process	The Working Paper does not demonstrate how the options would strength incentives on beneficiaries to participate in a context where they are unable to capture private benefits from such participation via capacity rights or some other contractual mechanism.	1
(b) efficient investment by generation and load, as allocating charges to beneficiaries means they would face some of the transmission cost implications of their investment decisions	Unless the charges approximate the change in transmission costs that generation or load give rise to (e.g. that the charges approximate LRMC of transmission capacity) such charges are likely to lead to less rather than more efficient outcomes over time. This inefficiency is of particular concern if the charges result in distortions in the energy market.	2
(c) allocative efficiency as charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge by non-beneficiaries would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which the charge reflects aggregate benefit	The Working Paper does not demonstrate that the options are superior in reducing deadweight losses than the existing RCPD charge. Shifting the charge to beneficiaries does not necessarily reduce these losses. Other aspects that need to be considered are the structure of the charge (whether capacity or energy based), the relative price sensitivity of those being charged, and their relative ability to reflect to consumers transmission charges as a fixed or capacity fee rather than bundling these charges in the energy price.	3

EA Assessment	Comment	No.
(d) productive efficiency as parties would not have incentives to limit their production to limit their charge liability as they may do under the status quo	The Working Paper does not demonstrate the options would promote productive efficiency more effectively than the status quo. To the extent that the options distort energy market bids and offers they are likely to be less efficient in this regard than the status quo.	4
(e) durability as charges would be calculated using an objective method that is flexible to changes in use of the grid and based on economic fundamentals.	It is incorrect to view the SPD beneficiaries-pay method as an objective method, as it would be entirely a creature of regulation and rests on many judgments and assumptions that reasonable people may differ on. The differences in the options in the Working Paper relative to the original proposal, and differences between these proposals, reveal a high level of subjectivity. We do not consider these options more durable than the status quo. The one issue that has been the source of most contention in transmission pricing over recent years is how the HVDC is priced. That source of contention could be addressed using variants of the status quo, and thus potential changes to that issue are not unique to the options in the Working Paper.	5
7.116 The likely costs of the proposal are:		
(a) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, any licence costs, development and testing	Agreed, and Transpower has indicated these costs would be substantial.	6
(b) operational costs to Transpower and the party applying the SPD method (if this was not Transpower), including the on-going costs of applying the option to estimate the benefits from transmission assets	Agreed, and Transpower has indicated these costs would be substantial. These costs could be mitigated by using the model to re-calibrate charges periodically only, e.g. once a year.	7

EA Assessment	Comment	No.
(c) costs to participants to verify their SPD charge	Agreed.	8
(d) inefficient investment to the extent that charging based on benefit does not reflect LRMC	Agreed, and is the counter to point (b) above. The Working Paper assessments assume (qualitatively) the net position will be positive for each option, but does not provide evidence for this assumption. As these benefits and costs operate in opposite directions the net position is determined by the quantum of each, that is it is an empirical issue.	9
(e) allocative and productive inefficiency to the extent that charging based on benefit does not reflect LRMC	Agreed, and is the counter to point (c) and (d) above. Also see comment 9.	10
(f) incentives for inefficient avoidance of the charge. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy.	This is an issue as the charges are not designed to approximate LRMC and the beneficiaries-pay criterion does not mitigate these inefficiencies. Other aspects that need to be considered are the structure of the charge (whether capacity or energy based), the relative price sensitivity of those being charged, and their relative ability to reflect to consumers transmission charges as a fixed or capacity fee rather than bundling these charges in the energy price.	11

EA Assessment	Comment	No.
Assessment of costs and benefits of GIT-plus-SPD option		
8.32 The benefits of the GIT-plus-SPD option are:		
(a) it would provide the same efficiency benefits as the simplified SPD charge in relation to relevant	The Working Paper does not demonstrate how these efficiencies would emerge, see	12

EA Assessment	Comment	No.
investments that would be subject to the SPD charge – that is, investments undertaken to lower the costs of generation	comments 1 & 2.	
(b) the GIT-based charge would:		
(i) promote efficient investment in relation to investments undertaken to provide reliability benefits as the GIT-based charge would align incentives to promote transmission investments to improve reliability with payment for those investments. This would provide strong incentives for expected beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment	We remain unconvinced participants will have the strong incentives that are relied on in this comment to achieve this benefit in the absence of contractual mechanisms that enable them to capture some of these private benefits. See also comment 1.	13
(ii) promote efficient investment by load, as allocating charges to beneficiaries of reliability investments means they would face the transmission cost implications of their investment decisions	As the charges would not approximate LRMC these charges would not reflect the "transmission cost implications of their investment decisions" (which is an incremental concept), and any resulting beneficiary behavioural response to them is likely, over time, to be inefficient. See also comment 2.	14
(iii) promote allocative efficiency as:		
• charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would be larger than under the simplified SPD charge option as no residual charges would	Not demonstrated, see comment 3.	15

EA Assessment	Comment	No.
apply to relevant reliability investments		
• it would promote efficient use of the grid as the only means of avoiding the charge would be to reduce load. This means relative to the simplified SPD charge alone there is a lower risk of inefficient behaviour to avoid the charge.	This assessment appears to consider the GIT-based charge would be superior on this point to the SPD charge, due to the GIT-based charge being (it seems) a capacity based charge. It would be useful if both of these charges were also assessed relative to the existing RCPD structure.	16
8.33 The likely costs of GIT-plus-SPD option are:		
(a) it would provide the same efficiency costs as the simplified SPD charge in relation to eligible investments that would be subject to the SPD charge – that is, investments undertaken to lower the costs of generation	Not clear this is correct as to the extent that this SPD charge collects a lower amount of revenue than the simplified SPD method these efficiency costs would also be lower.	17
(b) in relation to the GIT-based charge:		
(i) implementation costs for both Transpower and participants, including set-up costs involved in implementing the option	Agreed, but their quantum relative to the other options and the status quo are not estimated.	18
(ii) operational costs to Transpower, which would mainly relate to determining the allocation of the GIT-based charge to particular nodes and load at the node	Agreed, but their quantum relative to the other options and the status quo are not estimated.	19
(iii) costs to participants to verify their GIT-based charge. Participants could obtain assistance from third party providers, which would help limit the costs of this	Agreed, but their quantum relative to the other options and the status quo are not estimated.	20

EA Assessment	Comment	No.
(iv) inefficient investment to the extent that charging based on benefit does not reflect LRMC. This cost is likely to be lower under the GIT-based charge as, to the extent the investment is justified by the benefit received, the costs of the charge are likely to better reflect LRMC	Reliability investments can and do proceed where the assessed benefits are less than the costs (e.g. as was the case with the NAaN) so the assumption that such benefits will always exceed the costs does not hold. This comment also suggests that a charge lower than what the SPD model produces would be closer to LRMC and implies that movement toward LRMC is desirable. We agree with that view, which suggests the SPD method is the least attractive option on this criterion – this finding needs to be reflected in the assessment of the SPD method.	21
(v) inefficient investment to the extent that charges do not reflect actual benefit given changes in use of the grid over time, e.g. if the GIT-based charge applied at the Bromley substation in Christchurch the GIT-based charge would not reduce even though demand has reduced substantially at that substation. Similarly, by fixing the GIT-based charge the charge does not reflect the level of benefit immediately following an investment	We agree with the inefficiency issue and it reflects that the GIT based charge would not approximate LRMC. This comment also indicates this method would not over time reflect the level of benefit received. Thus it appears to have little to recommend it.	22
(vi) allocative and productive inefficiency to the extent that:		
• charging based on benefit does not affect LRMC	See comment 2.	23
• the allocation of charges does not reflect benefit over time as a result of changes to the pattern of use of the grid. To address this issue, the GIT-based charge could reset through regulation if there had been a substantial change in circumstances such as through a natural disaster	Agree that this rigidity in the GIT-based method is undesirable. It is also unclear what the basis would be for any reset.	24

EA Assessment	Comment	No.
(vii) incentives for inefficient investment to avoid the charge. This would mainly be an issue in areas subject to significant cost increases as a result of the charge – the upper North Island. While the ability of parties to alter their behaviour to avoid the charge is limited, the high level of the charge in the upper North Island would provide strong incentives on parties paying the charge in this area to disconnect from the grid or remain connected but install inefficient embedded generation. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy. However, full allocation of costs to beneficiaries increases the chance that inefficient investments will ultimately be borne by the Transpower shareholder, and therefore socialised more efficiently across the general tax base, rather than just electricity consumers.	This issue arises due to the charge not approximating LRMC. It is usual for a full cost allocation method to result in charges above LRMC, but this result does not imply the investment is inefficient. The challenge is to design a TPM that, amongst other things, minimises economic distortions while also enabling Transpower to recover its efficient costs. The possibility of socialising some transmission costs over the general tax base is novel and if the Authority is serious on this point it would be useful if it clarified what it has in mind.	25

EA Assessment	Comments	No.
Assessment of costs and benefits of SPD-plus-GIT option		
9.29 The benefits of the SPD-plus-GIT option are:		
(a) it would provide the same efficiency benefits as the simplified SPD charge in relation to relevant investments that would be subject to the SPD charge only – that is, investments undertaken to lower the costs of generation	Agreed they would be the same but note we expect these to be net costs (rather than net benefits) due to distortions in the energy market.	26

EA Assessment	Comments	No.
(b) it would better promote efficient investment in assets providing reliability benefits as the SPD charge would enable other benefits to be taken into account in beneficiaries-pay charging, and charging could reflect changing patterns in benefits over time	As these charges will not approximate LRMC, we expect any response to them in terms of beneficiary investments will be distorted by the charge, thus resulting in less rather than more efficient outcomes over time.	27
(c) relative to the GIT-plus-SPD charge, it would better promote:		
(i) efficiency as charging across a broader base of beneficiaries would mean lower charges to beneficiaries and a reduction in any incentives to seek to avoid the charge	We infer lower charges are desirable due to an assumption that they otherwise would be well above LRMC. If this is the case the better approach would be to set the charges to approximate LRMC.	28
(d) the GIT-based charge would:		
(i) promote efficient investment in relation to investments undertaken to provide reliability benefits as the GIT-based charge would align incentives to promote transmission investments to improve reliability with payment for those investments. This would provide strong incentives for expected beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment	See comment 13.	29
(ii) promote efficient investment by load, as allocating charges to beneficiaries of reliability investments means they would face the transmission cost implications of their investment decisions	As these charges will not approximate LRMC, we expect any response to them in terms of beneficiary investments will be distorted by the charge, thus resulting in less rather than more efficient outcomes over time.	30

EA Assessment	Comments	No.
(iii) promote allocative efficiency as:		
• charging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would be larger than under the simplified SPD charge option as no residual charges would apply to relevant reliability investments	See comment 3.	31
• it would promote efficient use of the grid as the only means of avoiding the charge would be to reduce load. This means relative to the simplified SPD charge alone there is a lower risk of inefficient behaviour to avoid the charge.	This assessment appears to consider the GIT-based charge would be superior on this point to the SPD charge, due to the GIT-based charge being (it seems) a capacity based charge. It would be useful if both of these charges were also assessed relative to the existing RCPD structure.	32
9.30 The likely costs of SPD-plus-GIT option are:		
(a) it would provide the same efficiency costs as the simplified SPD charge in relation to eligible investments subject to the option	Agreed.	33
(b) it would provide the same efficiency costs in relation to the GIT-based charge as for the GIT-plus-SPD option but the quantum of costs from distortions to behaviour from the charge may be lower because of a lower charge since some of the costs would be recovered through the SPD charge	Agreed.	34

EA Assessment	Comments	No.
(c) the combination of application of the SPD charge and the GIT-based charge to reliability assets may increase risk of allocative efficiency costs to the extent that parties subject to the SPD charge only seek to shift costs onto parties paying the GIT-based charge.	Agreed, which reflects an inefficiency in the design of the SPD charge if this "cost shifting" can occur.	35

EA Assessment	**Comments**	**No.**
Assessment of costs and benefits of zonal SPD option		
10.26 The benefits of zonal SPD option are:		
(a) it would promote efficient investment in transmission as parties benefiting from the investment – at least to the extent that this option charges costs to beneficiaries and according to their private benefit – would face the costs of the investment. This would be the case for investment that enables both transmission of power between zones and within zones. This would provide incentives on beneficiaries to participate in the investment decision-making and approval process and ensure all relevant information is considered in the decision on whether to undertake the investment	Not convinced as the Working Paper does not set out how these incentives will emerge in a context where beneficiaries do not have contractual mechanisms available to them to capture the private benefits, see comment 1.	36
(b) efficient investment by generation and load, as allocating charges to beneficiaries – to the extent this option charges costs to beneficiaries according to their private benefit – means they would face the	As the charges would not approximate LRMC these charges would not reflect the "transmission cost implications of their investment decisions" (which is an incremental concept), and any resulting beneficiary behavioural response to them is	37

EA Assessment	Comments	No.
transmission cost implications of their investment decisions	likely, over time, to be inefficient. See also comment 2.	
(c) allocative efficiency through reduction in deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge would be paid for by beneficiaries. The reduction in deadweight loss would depend on the extent to which beneficiaries are charged and the charges reflect aggregate benefit	See comment 3.	38
(d) productive efficiency as parties would not have incentives to limit their production in order to limit their charge liability as they do under the status quo.	See comment 4.	39
10.27 The likely costs of the zonal SPD option are:		
(a) implementation costs are likely to be high for both Transpower and participants, including set-up costs involved in designing and implementing the option, including computer equipment, any licence costs, development and testing	Agreed, but their quantum relative to the other options and the status quo are not estimated.	40
(b) dispute costs from establishment of zones and interconnectors	Agreed these costs would arise under this option but we consider they would also arise under the other options due to their complexity and the need for a wide range of judgments to be made to implement them.	41
(c) operational costs to Transpower, or to a party other than Transpower if the role of applying the method to calculate inter-zonal charges was subject to tender, including the on-	Agreed, but their quantum relative to the other options and the status quo are not estimated.	42

EA Assessment	Comments	No.
going costs of applying the option to estimate the benefits from transmission assets		
(d) costs to participants to verify their charges	Agreed, but their quantum relative to the other options and the status quo are not estimated.	43
(e) inefficient investment to the extent that charging does not reflect benefit and does not reflect LRMC	The inefficiencies would arise due to the charges not reflecting LRMC, not due to them not reflecting private benefits.	44
(f) allocative and productive inefficiency to the extent that charging does not reflect benefit and does not reflect LRMC	The inefficiencies would arise due to the charges not reflecting LRMC, not due to them not reflecting private benefits.	45
(g) incentives for inefficient avoidance of the charge. This would need to be addressed through the design of the charge or through other mechanisms, such as the prudent discount policy.	This inefficiency would arise due to the charge not approximating LRMC.	46