MAJOR ELECTRICITY USERS' GROUP

28 February 2013

Dr John Rampton
General Manager Market Design
Electricity Authority
By email to submissions@ea.govt.nz

Dear John

Consultation Paper – Transmission Pricing Methodology: issues and proposal

1. This is a submission by the Major Electricity Users' Group (MEUG) on the Electricity Authority (EA) consultation paper "Transmission Pricing Methodology: issues and proposal" published 10th October 2012[1].

2. This submission comprises three parts. First, this cover letter. Second, the appendix to this letter with responses to the questions in the consultation paper. Third, a separate independent report by the New Zealand Institute for Economic Research (NZIER) "Transmission Pricing Methodology 2012: Evaluation of EA consultation paper".

3. Members of MEUG have been consulted in the preparation of this submission. Several MEUG members will be making submissions. This submission is not confidential.

Summary of MEUG submissions

4. Our summary response to each chapter in the consultation paper, beginning with chapter three, follow. Preceding the summary of responses are comments on the consultation process.

5. On the consultation process MEUG note:

   - As the consultation has involved over 600 pages in reports, 100s of Megabytes of data and numerous spread sheets and other material that has emerged over the last 5 months it has been particularly difficult for consumers to participate in this process. The extension by the Authority to the consultation period has proven to be necessary; though given the complexity of the proposal the Authority could have anticipated a much longer consultation period than originally set.

[1] http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

- In December the Authority published an analysis on the effect on retail customers by distribution network. These have been helpful because where wealth transfer effects are material then it is important they are understood to assess any flow on economic impact that they may induce as well as the future litigation and or political durability risks.

- MEUG and MEUG members have found engagement with the Authority staff very good and requests for meetings, information or model runs have been forthcoming. Nevertheless the complexity of the task has been daunting[2], costly and affected the confidence of MEUG members. The latter cannot be understated. There is frustration and angst at another completely new approach to TPM where it is difficult to be certain consumers will benefit. There is also real concern over increased complexity, less transparency and the inherent transmission cost uncertainty.

- Time and resources spent by MEUG members, MEUG and the industry as a whole on the October 2012 TPM consultation paper has diverted attention from other opportunities to improve the efficiency and productivity of the market. We elaborate on those other priorities in the following section "next steps" in paragraph 12 b) iv).

- The sense of urgency to consider if changes to the existing TPM are needed should be reassessed in light of minimal expected future new grid investment proposals. At a minimum a refresh of the TPM was needed given the change in statutory objective from that of the Electricity Commission to that of the Authority. However this change does not of itself seem sufficient to necessitate the urgency attached to this proposal. A better process may have been to consult on alternatives including an option based on the new SPD allocation method. That consultation would have uncovered structural and implementation issues in implementing the SPD allocation approach. The Authority could then have made an informed decision on the costs and benefits of further developing the SPD method now compared to refreshing the existing TPM in the interim and planning work to develop the SPD method and other near market approaches for a TPM change ahead of when any future major grid expansion decisions are needed.

- There are risks of lack of synchronisation with the Commerce Commission regulatory regime governing Transpower and the new emerging policy issue of managing uneconomic grid assets should demand decline or remain flat.

6. The decision-making and economic framework decided in 2012 is, however, still sound (chapter 3).

7. We do not accept that problems with the current TPM for allocating sunk costs are material enough to justify significant changes (chapter 4) where the efficiency gains from re-arranging sunk costs are not obvious. We do believe the previous regulated processes for Transpower to gain approval for capital expenditure failed end consumers. The jury is out on the more recent shift of responsibility for regulation of Transpower to the Commerce Commission and Ministry of Business Innovation and Employment (MoBIE). There also is a fundamental policy question as to whether Transmission assets that are clearly uneconomic should be written down. This is an increasingly realistic scenario as peak demand growth for grid services may decline with the emergence of new demand side response and distributed generation technologies.

[2] By way of illustration the Authority published on 18th February 2013 responses to 62 questions asked at the Authority workshop on 7th February 2013. Some of those questions traversed new ideas that MEUG has had insufficient time to fully consider in preparing this submission.

8. The core of the proposal is considered in chapter 5 of the consultation paper. In summary MEUG submit:

   - A re-think is needed of two aspects of the treatment of loss and constraint excess (LCE). First, is there a material policy problem with the existing LCE rebate process? Second, if the proposal is adopted then allocating LCE against individual grid assets needs to be re-considered.

   - On the SPD allocation approach we note NZIER (p ii) are supportive of the approach in relation to future grid investments but have important caveats around synchronisation with the whole regulatory regime and risk of unintended consequences particularly with demand uncertainty. Applying the SPD allocation approach to sunk transmission costs (NZIER p iii) is even more problematic and NZIER detail "shortcomings" of no provision for demand side response, the residual will be large for many years and that has issues including difficulty of avoiding generators being able to pass residual charges through to customers, the effect on embedded generation and a number of "structural flaws" or design elements where possible unintended outcomes have not be adequately considered.

   - On the treatment of the residual we note the view of NZIER (paragraph 120, p 33) that:

     "*The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges*."

   - NZIER's summary view of the cost benefit analysis is (p iv) that:

     "*The EA's empirical analysis of costs and benefits is at best illustrative and leaves us unconvinced that the scale and scope of the purported net benefits will be realised*".

9. Given the assessment by NZIER that the proposal is not supported by a robust cost benefit analysis and further work is needed; then this will require reconsideration of the work in chapter 6 on alternative means of achieving the objectives.

10. We do not support the proposed guidelines for Transpower (chapter 7) because it is premature to draft those until this proposal is modified and that such a modified proposal is tested against other feasible options in a more robust cost benefit analysis framework.

11. Overall, MEUG recommend the Authority consider the expert independent views of NZIER (p iv) of the October 2012 TPM guidelines proposal:

    - *"As economists we are attracted to the proposal because it is a better approach to the TPM than the status quo and if structured appropriately and implemented to be durable it could improve the performance of the electricity sector. Having said that, the details of how it tackles a very difficult and complex issue makes it hard to see how it will be successful in its objectives.*

    - *The EA's empirical analysis of costs and benefits is at best illustrative and leaves us unconvinced that the scale and scope of the purported net benefits will be realised.*

- *We also have concern that, if applied as is, the SPD approach will be unable to avoid precipitating material unintended outcomes that would likely result in a transmission pricing environment that is worse than the status quo. We suggest that the EA reconsider the SPD methodology as a whole and give attention to the issues that we describe in our assessment.*

- *The inclusion of HVDC pole 2 troubles us. We say this because of the likelihood that the HVDC HAMI charge has already been factored into SI generators asset values. If this is the case, then the current HVDC charge has no (or no material) impact on generation investment and consumer prices and there is no real resource cost , meaning that a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in dynamic efficiency."*

Next steps

12. The industry needs clarity on what might happen next. Following on from the views on the proposal and process above, MEUG suggest the Authority:

    a) Does not issue the guidelines in the proposal to Transpower;

    b) Consults on possible next steps for reviewing the TPM taking into account that:

        i) Opportunities to improve the proposal suggested in submissions that could justify further investigative work, and any new options not considered by the Authority.

        ii) The cost benefit analysis methodology for assessing possible changes to TPM needs to be developed that is both broader in scope (to offset risk of unintended consequences in the wider market and regulatory designs) and is predicative rather than illustrative.

        iii) The level of grid investment for the next decade is likely to be modest at best.

        iv) There are many other opportunities for improvement in the market that are competing with resources that might otherwise be used on a review of TPM. The cost and possible benefits of work on i) and ii) above should be present valued taking into account the much reduced and longer term need to improve grid investment decision making, and weighed against the costs and benefits of other urgent work.

        In particular MEUG has concerns work on Dispatchable Demand and other Code and market design changes[3] to enable a range of direct demand side participation in the discovery of efficient spot prices, has been a neglected poor second cousin to TPM.

[3] This includes work being considered by the Wholesale Advisory Group on understanding the detriments from and options to solve the problem of miss-alignment of forecast spot and final settlement prices.

v) How other policy options not within the scope of the Authority can be considered in future consultation rounds. For example there must be a point where existing grid assets are clearly uneconomic and the option of Transpower writing down the value of those assets is the best policy option. We see no downsides to the Authority taking the lead on developing a work programme on this option provided the Commerce Commission and MoBIE are involved.

c) Irrespective of whether further development work is undertaken on the SPD approach for TPM, the Authority and Commerce Commission should jointly develop a process for regular publication of benefits accruing to participants from individual transmission assets using an improved SPD type analysis. By improvements we mean implementing changes for flaws identified by NZIER and other parties. Publication of this material will put the spotlight on prior uneconomic grid investment decisions and be a constant reminder that calls by Transpower and others for new grid investment need to be more thoroughly tested than they were in the past. Quarterly publication of such an analysis would be a good start.

13. There are four other steps MEUG intend to take:

a) To follow up with Ministers on the difficulty end customers have to engage and provide quality input into such complex issues as TPM. This problem was highlighted in the High Court merit review last year of the Commerce Commission Input Methodology decisions. The status quo is not sustainable as differences of view on changes and implementation of the Electricity Industry Participation Code 2010 and Part 4 of the Commerce Act become more litigious in nature.

b) To reinforce with Ministers the problems in getting traction on Dispatchable Demand and other Code and market design changes, to enable a range of direct demand side participation in the discovery of efficient spot prices as noted in paragraph 12 b) iv) above. Ministers are already aware of our concerns on this topic[4].

c) To seek support from Ministers that officials from MoBIE work with the Authority and Commerce Commission to consider under what circumstances might clearly uneconomic existing grid assets necessitate a write down in value by Transpower. Given the possibility that peak demand growth will decline, this is a very important policy question not just for the valuation of Transpower, but also electricity distributors.

The question of adapting Part 4 of the Commerce Act for a future paradigm where existing sunk monopoly assets will be stranded is a follow on issue. For example should Optimised Deprival Valuation and the $20m cut off for Commission consideration of major transmission capital items be re-considered?

[4] Refer MEUG letter to Transpower copied to Ministers, "Transmission charges and market facilitation measures", 11th September 2012, page 4, published at http://www.meug.co.nz/includes/download.aspx?ID=123971.

d) To discuss with Ministers if more certainty is needed on the timing of review processes. This has been an issue for MEUG with respect to post-implementation reviews needed for the stress test requirements for example. In that case market participants subject to the stress test requirements incur compliance costs every quarter for publication of an aggregate view of market stress test management that is meaningless. There is no regulatory requirement for the Authority to undertake a review of that policy within a certain timeline. With TPM the certainty we would like is the TPM to be reviewed no earlier than predefined periods. We do not want the review of allocating sunk costs under the TPM to be an ongoing work stream for the next decade.

14. We would welcome an opportunity to discuss or clarify any part of this submission.

Yours sincerely

Ralph Matthes
Executive Director

Appendix: MEUG responses to questions in the October 2012 TPM consultation paper

<table>
<tr><th colspan="2">Question</th><th>MEUG response</th></tr>
<tr><td colspan="2"></td><td><u>Chapter 2 Context to transmission pricing</u></td></tr>
<tr><td>1</td><td>What are your views about the materiality of changes in circumstances since the current TPM came into force in 2008?
(Refer Para 2.3.12, p34)</td><td>Agree with the points in paragraph 2.3.9 with the following caveats:
• The change in statutory objective from the EC to EA leads to a need for the EA to review the TPM, but that does not necessarily require urgency.
• The already approved investment programme of over $2 billion needs to be recovered. If dynamic efficiency effects matter most, it's the role of TPM to improve future investment decisions that is of greater importance. The future grid investment plan is very small for the next decade at least and this should be a factor in considering the urgency and scale of any near term changes to TPM.
• Agree technology is an enabler to allow TPM methodologies such as the SPD allocation approach to be considered whereas they were not computable even five years ago. The impact of technology has an even more important role in the future demand for grid connection services. The innovation and cost of demand side response technologies and distributed generation (and this includes electric vehicles as generators under some scenarios) may lead to declining demand for peak grid connection services.
The TPM and other components of the regulatory regime need to address the question of who should bear the asset value write down of existing assets under such scenarios?
The ongoing effects of the Global Financial Crisis along with the high exchange rate have been felt throughout the economy with profit margins squeezed affecting investment and employment decisions by large and small businesses. The TPM needs to improve future decision making but also be mindful that making changes to the current TPM for cost recovery of sunk assets may have wealth effects that tip businesses into further financial stress and possibly closure. The timing of significant changes to TPM needs to consider both long and near term impacts.</td></tr>
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Question		MEUG response
2	What comments do you have on the process that the Authority has outlined for developing and approving a new TPM? Describe and explain any variations to the process that you consider desirable. (Refer Para 2.3.19, p36)	The EA needs to consider any complimentary changes to regulation under Part 4 of the Commerce Act or any other regulation to maximise benefits and or lower costs of any TPM amendment.
		Chapter 4 Problem definition: does the current TPM promote overall efficiency?
3	Do you agree with the Authority's view that the arrangements under the TPM for recovering connection costs are generally efficient? Explain your answer. (Refer Para 4.2.12, p49)	Yes.
4	What comments do you have about the potential for inefficient outcomes to arise from incentives to shift connection costs into the interconnection charge? (Refer Para 4.2.19, p51)	Agree some existing boundary issues are creating inefficient incentives.
5	Do you agree that there is the potential for inefficient outcomes to arise from incentives for connected parties to hold out for connection asset replacement to occur as a grid upgrade rather than under an investment contract? Explain your answer. (Refer Para 4.2.23, p52)	Agree.
6	Do you consider that there are any other problems with the connection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem. (Refer Para 4.2.23, p52)	We have not identified any other issues.
7	What comments do you have about the Authority's analysis of the private benefits deriving from the HDVC link? (Refer Para 4.3.11, p55)	The expectations and asset values of South Island generators when they were first established and or listed and subsequent re-valuations also needs to be considered.
8	What comments do you have about the consequences of the material differences between private benefits from the HVDC link and HVDC charges? (Refer Para 4.3.11, p55)	The EA gives no evidence of the claim of "significant economic cost" noted in paragraph 4.3.11. MEUG is not convinced that issues with the current TPM in relation to the HVDC are significant given the forecast flat demand and little need for large increments of generation. We believe that the benefits to South Island generators are materially above HVDC charges.

Question		MEUG response
9	What comments do you have about the Authority's analysis of the costs of inefficient generation investment resulting from the HVDC charge? (Refer Para 4.3.13, p56)	MEUG note NZIER in their overall view (p iv) regarding the inclusion of HVDC Pole 2 in the SPD approach include the comment: "*The inclusion of HVDC pole 2 troubles us. We say this because of the likelihood that the HVDC HAMI charge has already been factored into SI generators asset values. If this is the case, then the current HVDC charge has no (or no material) impact on generation investment and consumer prices and there is no real resource cost , meaning that a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in dynamic efficiency.*"
10	What comments do you have about the Authority's analysis of the costs of inefficient operation of South Island generation resulting from the HVDC charge? (Refer Para 4.3.15, p56)	Minor effect at best. More likely immaterial or nil effect.
11	Do you consider that there are any other inefficiencies arising from the HVDC charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the inefficiencies. (Refer Para 4.3.15, p56)	We have not identified any other issues.
12	What comments do you have about a) the differences (including their materiality) between private benefits from interconnection assets and interconnection charges; and b) the consequences of those material differences? (Refer Para 4.4.17, p61)	We agree there are significant differences between what some parties pay for transmission services under the existing TPM and the benefits they receive. In some cases the difference is negative and in other cases positive. This outcome is expected of any administrative approach. The question to be considered for any proposed change is whether it simply shifts the incidence and inequities or creates demonstrable efficiency gains.
13	What comments do you have about the Authority's analysis of the problems with interconnection charges? (Refer Para 4.4.17, p61)	See response to Q 12 above.

Question		MEUG response
14	Do you consider that there are any other problems with the interconnection charging arrangements under the current TPM? Provide a detailed explanation of the nature and materiality of the problem. (Refer Para 4.4.17, p62)	We have not identified any other issues apart from the failure of the existing interconnection charges to complement the investment decision making process to avoid uneconomic assets being built. We believe that it is critical that grid planning and transmission pricing are conducted in tandem and are tightly synchronised.
15	What comments do you have about the Authority's view that a prudent discount policy may be necessary after taking into account the incentives provided by the price components of any revised TPM? (Refer Para 4.6.8, p66)	Agree with the views in the paper.
		<u>Chapter 5 Proposed amendments to the TPM</u>
16	What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals? (Refer Para 5.3.14, p77)	We are unsure what policy problem the proposed change is intended to solve. On the proposal itself we understood LCE or residual LCE sums as a whole would reduce the aggregate revenue requirement then allocated by the SPD allocation and residual allocation methods. We only became aware in February 2013 that the proposal was to net LCE or residual LCE from the revenue requirement of specific assets. That approach will have detrimental effects on options for using LCE or residual LCE for further hedge options to manage Within-Island-Basis-Risk.
17	Do you agree there would be efficiency gains from each of the components of the proposal for the connection charge, as outlined in paragraph 5.4.9? Please provide an explanation for your answer. (Refer Para 5.4.15, p80)	Yes.
18	Do you agree that the proposal will address the problem identified in chapter 4 in relation to the connection charge? Please give reasons for your views. (Refer Para 5.4.15, p80)	Yes
19	What comments do you have about the Authority's assessment and conclusions about a kvar charge to recover static reactive support costs? (Refer Para 5.5.23, p85)	Proposal is reasonable.

Question		MEUG response
20	Do you support: a) introducing a kvar charge based on off-take transmission customers' average aggregate kvar draw from the grid in areas where investment in static reactive support is likely to be required, at times of RCPD, at the long run marginal costs of grid-connected static reactive support investments? b) setting a minimum power factor of 0.95 lagging in the Connection Code for all regions? (Refer Para 5.5.23, p85)	Proposal is reasonable.
21	Do you consider that there are alternatives to a kvar charge for recovering the static reactive support costs that the Authority has not identified that are practicable, would deliver a net benefit and would recover static reactive support costs? Explain your proposal. (Refer Para 5.5.23, p85)	Proposal is reasonable.
22	What comments do you have about the Authority's assessment and conclusion about charging options for dynamic reactive support? (Refer Para 5.5.26, p86)	Agree that charges for dynamic reactive support should align with how interconnection and HVDC assets are recovered.
23	What is your view of the Authority's assessment and conclusions about using the SPD or vSPD model to establish a beneficiaries-pay charge for recovering some or all HVDC and interconnection costs? (Refer Para 5.6.60, p99)	We note NZIER (p ii) are supportive of the approach in relation to future grid investments but have important caveats around synchronisation with the whole regulatory regime and risk of unintended consequences particularly with demand uncertainty. Applying the SPD allocation approach to sunk transmission costs (NZIER p iii) is even more problematic and NZIER detail "shortcomings" of no provision for demand side response, the residual will be large for many years and that has issues including difficulty of avoiding generators being able to pass residual charges through to customers, the effect on embedded generation and a number of "structural flaws" or design elements where possible unintended outcomes have not be adequately considered.

Question		MEUG response
24	Do you agree with the Authority's conclusion that the most efficient beneficiaries-pay charging option for applying to HVDC and interconnection costs is likely to be the SPD method? Please provide an explanation for your answer. (Refer Para 5.6.65, p101)	See response to Q23.
25	Do you consider that there are beneficiaries-pay options that the Authority has not identified that are practicable, would deliver greater net benefits and would recover HVDC and interconnection costs? Explain your proposal. (Refer Para 5.6.65, p101)	We have not identified any other options. MEUG members are likely to suggest options that need to be considered further. We are not convinced that capacity rights can be dismissed as an option.
26	Do you agree with the proposal to apply the residual charge to: a) generators and direct-connect major users; b) distributors, except where they opt out from the charge; and c) retailers, were distributors elect to opt out from the charge? (Refer Para 5.6.78, p104)	On the treatment of the residual we note the view of NZIER (paragraph 120, p 33) that "*The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges*."
27	Do you agree with the proposal that distributors may opt out from the residual charge: a) to the extent that they do not benefit from offering interruptible load on the wholesale electricity market; and b) provided they consult with retailers that may be affected before they opt out? (Refer Para 5.6.78, p104)	We wish to consider the submissions of retailers, EDB and other interested parties in this consultation round before taking a view on this proposal.

Question		MEUG response
28	Do you consider that the proposed RCPD/RCPI charge, designed to encourage efficient avoidance of peak regional use of the grid, with half of the residual revenue recovered from load and half from generators, would best complement a beneficiaries-pay charge that calculates charges every trading period using the SPD model? Explain your response. (Refer Para 5.6.92, p107)	On the treatment of the residual we note the view of NZIER (paragraph 120, p 33) that "*The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges*."
29	Do you agree that the RCPD/RCPI charge would best meet the principles for an alternative charging option of: a) minimising the distortion in use of the transmission grid resulting from the imposition of charges; and b) ensuring the costs of providing the transmission grid, as approved by the Commerce Commission, are fully recovered so future investment is not stifled by concerns by investors that they will not receive a return on their approved investment? Explain your response. (Refer Para 5.6.92, p107)	No. In extreme cases where clearly an investment is uneconomic, then Transpower should bear some of the pain with a partial asset value write down.
30	Do you agree that the Authority's preferred option for the residual charge should be an RCPD/RCPI charge designed to encourage efficient avoidance of peak regional use of the grid? Explain your response. (Refer Para 5.6.92, p107)	On the treatment of the residual we note the view of NZIER (paragraph 120, p 33) that "*The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges*."
31	What are your views about amending the existing prudent discount policy to provide that it: a) applies to disconnection of load as a result of investment in generation where this would not be privately beneficial in the absence of transmission charges; and b) may apply for the expected life of the asset to which the prudent discount applies? (Refer Para 5.6.105, p110)	These proposals seem reasonable.

Question		MEUG response
32	Do you agree with the assessment of the economic costs and benefits of the Authority's TPM proposal versus the counterfactual? Explain your answer. (Refer Para 5.7.26, p114)	No. MEUG notes NZIER's overall view (p iv) that: "*The EA's empirical analysis of costs and benefits is at best illustrative and leaves us unconvinced that the scale and scope of the purported net benefits will be realised*
33	Do you agree with the assessment of the costs and benefits of the TPAG majority proposal against the counterfactual? Explain your answer. (Refer Para 5.7.26, p114)	No.
34	Do you agree that the Authority's TPM proposal meets the Authority's objective? Explain your answer. (Refer Para 5.8.6, p117)	No.
		<u>Chapter 6 Evaluation of alternative means of achieving the objectives</u>
35	What comments do you have about the Authority's evaluation of alternative market-based and market-like approaches for the recovery of transmission costs? (Refer Para 6.3.61, p133)	Long-term contracts, capacity rights or offer rights and merchant transmission are market based options. Current RCPD charge, MWh charge and Incentive-free are all market alternatives. We would expect in terms of improving efficiency, that market based options would rank higher than market alternatives. That expected relative ranking is not shown in table 10 (p119). We suggest the number of ticks for each option under the column headed "efficiency" for the market based options should be greater than the ticks assigned to each market alternative option. Also in table 10 when comparing the market alternative options, MWh charge is considered more efficient (2 ticks) compared to the current RCPD charge and incentive-free options (1 tick each). We don't think given the subjective nature of this measure that any differentiation between the three market alternatives can be made. More consideration of the merchant transmission option should be made because, while it may be unlawful to include such an option in the TPM (refer paragraph 6.3.39, p129), it may be a good economic solution and it's the regulatory regime that needs to change to accommodate such an option.

Question		MEUG response
36	What comments do you have about the Authority's acceptance of the TPAG's evaluation of alternative exacerbators pay approaches for the recovery of network reactive support costs? (Refer Para 6.4.3, p134)	Agree with the EA (paragraph 6.4.3) that "the work carried out by the TPAG on network reactive support was robust and remains relevant."
37	Do you agree with the Authority's assessment and conclusions about alternative beneficiaries pay options for establishing transmission charges to recover HVDC and interconnection costs? Please give reasons for your views. (Refer Para 6.5.44, p143)	We agree the zonal option (not really a true beneficiaries pay option, but (paragraph 6.5.33) an "intermediate between beneficiaries pay and alternative charging options") is less attractive than using flow tracing which in turn is less attractive than use of economic models. The opening sentence of paragraph 6.5.14 states "The option of using economic models is considered superior to the status quo, but inferior to the Authority's proposal to use SPD to identify beneficiaries and private benefit." We do not think the consultation paper provides the evidence to support this statement. In the next sentence of paragraph 6.5.14 the argument that the SPD allocation method is superior to use of economic models is stated as "That is because, unlike the Authority's proposal, it (that is economic models) would not use direct wholesale market outcomes to determine benefit but rely instead on forecasts and modelling assumptions." MEUG notes that a fundamental flaw in the SPD proposal is that the consumer surplus is calculated using non-market assumptions rather than actual bids. Therefore the criticism that economic models use non-market assumptions can also in part be levelled at the SPD allocation method.
		<u>Chapter 7 Proposed guidelines for Transpower</u>
38	Do you consider that the draft guidelines provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? Explain your answer. (Refer Para 7.8.2, p154)	The guidelines need more clarification of how the residual is to be treated because that will be highly contentious as some parties will as a result of summing their SPD allocation and residual allocation pay more for transmission than the benefits they derive. This will result in inefficient incentives and outcomes. Transpower is indifferent to these effects on its customers and flow on effect to end consumers; whereas the EA should have an appreciation of the scale of likely inefficient outcomes and incentives and give commensurate greater guidance to Transpower.

Question		MEUG response
39	Do you have any suggestions for amendments to the draft guidelines to ensure that they provide the guidance necessary for Transpower to develop a TPM that reflects the Authority's preferred option? (Refer Para 7.8.2, p154)	No views because the regime needs re-assessing before guidelines can be drafted.
		<u>Chapter 8 Draft process for development and approval of TPM</u>
40	Do you agree with the Authority's proposed process that Transpower should follow in developing the TPM? Explain your answer. (Refer Para 8.2.7, p156)	Seems reasonable.
41	Do you agree that the Authority does not need to require Transpower to propose how costs related to revenue not subject to regulatory review by the Authority or the Commerce Commission would be determined and allocated? Explain your answer. (Refer Para 8.2.7, p156-157)	Agree.
42	Do you have any suggestions for amendments to the Authority's proposed process that Transpower should follow in its development of the TPM? (Refer Para 8.2.7, p156-157)	No.
43	Do you have any comments about the Authority's proposal that Transpower should propose a timeframe to the Authority that would achieve the Authority's objective of having the amended TPM in place in time for the April 2015 pricing year? (Refer Para 8.2.7, p156-157)	As well as proposing a plan to have invoices from 1st April 2015 based on a new TPM, we suggest Transpower advises the EA of: • The cost to achieve a 1st April 2015 deadline; and • The alternative cost if implementation were delayed to 1st April 2016. If there was a material decrease in implementation costs with a delay, then the EA could weigh the savings in implementation costs against forgoing benefits in deciding optimal timing.
44	Do you agree with the Authority's proposal to decide on the consultation period after the proposed TPM has been received from Transpower? (Refer Para 8.3.3, p158)	Yes.