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Final Report | 23 February 2017

Expert Review of Expert Reviews of Transmission Pricing Methodology Reform Proposals

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Preface

The genesis of this report was the concern of a group of stakeholders that the Electricity Authority had not fully engaged with the expert advice it had received in its review of the current Transmission Pricing Methodology (TPM), and its process to develop replacement TPM Guidelines.

These stakeholders considered that both the number of issues "in play", and the duration of the process to date, meant that there was a substantial risk that views expressed early in the process would not be re-considered at a later stage – even though they remained relevant.

This risk is of course heightened by the sheer volume of submissions lodged since 2012.

To address this risk, the stakeholders decided to seek advice from a further expert, on the conclusions of the experts. Trustpower and its counsel acted on behalf of the group in commissioning that advice.

Those stakeholders are:

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1 Executive Summary

1. Electricity flows from large power stations (generation) to end users (load) through a high voltage transmission network (the national grid) and then through many lower voltage local distribution networks. The costs of providing services from the transmission grid are mostly fixed: they do not change with the flow of power to end users. This report is about how best to recover the costs of the transmission grid from generation and load users. It is a difficult economic problem: the common ground, here and internationally, is that there is no perfect system.

2. In New Zealand, investment in the grid (e.g. expansion or replacement) is controlled by the Commerce Commission, which also regulates the earnings of Transpower, the grid owner and operator. A separate regulator, the Electricity Authority (EA), is responsible for the transmission pricing methodology (TPM), which governs the *way* Transpower earns revenue, i.e. the structure and design of its prices. In practice, the EA's role is to determine *guidelines* that Transpower must respect when setting prices and to approve the TPM that Transpower develops to meet those guidelines.

3. The existing TPM was set in 2008 and involves just three charges: one that recovers the cost of connection assets from those connecting to the grid, one that bills South Island generators for the high voltage direct current (HVDC) link that connects the North Island to the South Island, and a fairly simple "interconnection" charge on load to recover all other costs.

4. The EA has been actively seeking to change the TPM since January 2012. Since then, it has issued twelve consultation papers, including two substantive proposals for new TPM Guidelines and (most recently) a supplement to the second set of proposals. There are three common threads to the EA's views on and proposals for new TPM guidelines since October 2012: there should be no separate HVDC charge; beneficiaries of particular interconnection transmission assets should pay for those assets (which is now referred to as an area-of-benefit or AoB charge); and this regime should be backdated to include all assets approved for installation since 2004.

5. In response to these EA initiatives, sixty reports have been filed by expert analysts, along with a much larger number of submissions filed by individuals and firms participating in the electricity industry. In this review, I examine the expert reports, assess them against a set of propositions relevant to New Zealand's TPM, and express my own opinions on the basis of this information set and other information as cited below.

6. This review was commissioned by counsel acting for Trustpower. I have read and agree to be bound by the High Court's code of conduct for expert witnesses in preparing this report. My qualifications for this task are in my CV which is appended.

Factual Background

7. Under the Electricity Industry Participation Code 2010, the EA may review the TPM if it considers there has been a "*material change in circumstances*". Transpower invested very little capital in the decade up to 2006, after which investment levels rose, peaking in 2012 and 2013 at over $800m per annum. Much of this investment was to improve capacity to

deliver power into Auckland from the south. In its 2012 review of the TPM, the EA cited Transpower's *"significant capital expenditure programme"* as one of the reasons it believed there was a *"material change in circumstances"* warranting a review of the TPM. The other two changes cited by the EA were *"the establishment of a new regulatory regime in 2010 (including the establishment of the Authority)"*[1], and *"advances in computing capabilities"*. In parallel with this review of the current TPM, the EA also developed a set of replacement TPM Guidelines.

8. It appears likely that the EA's TPM initiatives are based in part on a view that some of this recent capital investment was inefficient, though I have not been able to locate evidence of such inefficiency, nor (to my knowledge) has the EA explicitly claimed that inefficient investment has occurred. Instead, I have inferred that this is the EA's belief, based on regular statements in the EA's TPM consultation documents regarding dynamic efficiency concerns with the existing TPM Guidelines, including the view that the existing TPM Guidelines give market participants inefficient incentives to lobby for/against particular grid investment proposals.

1.1 Economic Issues with TPM Reform

9. The expert reports reviewed agree with the EA that there is no perfect TPM: many experts explicitly agree with this point, and none have disagreed. The absence of a perfect solution can be seen by considering the *timing* of decisions that the TPM might seek to influence.

10. If the current pattern of demand for, and supply of, electricity were somehow frozen in time, it would be quite simple to design an efficient two-part tariff with low usage charges (in line with the very low short-run costs of transmission) and a fixed fee (such as a daily charge for connections) that recovered all other costs. This is a generally agreed solution to the *short-run* task of designing an efficient TPM. Moreover, several experts consider that New Zealand's existing TPM Guidelines, when viewed alongside other relevant aspects of the electricity industry, already provides adequately for short-run efficiency (also known as *static* efficiency).

11. But the level of demand is not fixed forever. As demand for electricity has grown, generators have invested in extra capacity to meet growing demand, and the capacity of the grid has expanded in response, with the overall aim of keeping the lights on. These growth and investment changes bring in a second, *long-run*, concern that massively complicates the problem of designing an efficient TPM. Once we add the second objective, to *promote efficient investment* in assets that affect the supply-demand balance, there is no perfect TPM design. Many of the source documents for this review refer to *dynamic* efficiency: this concept refers to the efficient timing, scale and location of new investment.

12. My view of the EA's consultation papers, and the expert reports responding to those papers, is that everyone agrees that there is no fully efficient solution *because* no TPM can simultaneously provide fully efficient short-run and long-run incentives while also

[1] I infer from this quote that the input methodologies that were determined by the Commerce Commission in 2010 pursuant to amendments to the Commerce Act were viewed by the EA as contributing to a material change in circumstances.

covering Transpower's costs. The TPM Guidelines design task is therefore to minimise inefficiencies, which requires compromise through a trading-off process.

Separability of Short- and Long-Run Decisions

13. A threshold question is whether the Commerce Commission can be trusted with the task of screening major transmission investments. Put slightly differently: would a TPM aimed at maximising short-run efficiency compromise the Commerce Commission's ability to make wise long-run decisions on major transmission investments?

14. This is an important question because Parliament has designed the existing separation of powers between the two regulators, such that the EA's main role in transmission regulation is to design *guidelines* that Transpower must following in setting the TPM. It would be a neat solution to the insoluble general problem if the TPM could focus on short run efficiency and leave the Commerce Commission to assess major transmission investments (i.e. the long-run aspect). Moreover, since there is no perfect answer to the combined short and long run problems, even the risk of an occasional mistake by the Commerce Commission might be acceptable when compared with the alternative.

15. The EA does not accept that the Commerce Commission can be relied on to prevent inefficient grid investment.[2] Instead, reinforcing my conjecture (¶8) that the EA doubts the Commerce Commission's ability to screen investment plans efficiently, the EA presents three counter-arguments in its second issues paper. First, it says that *"even if the Commerce Commission had perfect information and foresight, a TPM that provides inefficient price signals will cause inefficient use of the grid, which will lead the Commerce Commission to approve the set of efficient investments that allow grid users to use the grid inefficiently"*. I agree with Axiom who responded that this *"theory does not represent the practical context in which such investment processes take place"*.

16. The EA's second argument concerns incentives to reveal information to the Commerce Commission: *"a TPM that provides poor price signals alters the incentives on parties to provide information to, and engage with, the Commerce Commission, harming its ability to effectively test Transpower's proposals against other options"*. The EA's third argument was over durability: *"a TPM that is fundamentally inconsistent with the principles of efficient pricing is not durable"*.

17. None of these three arguments are supported by evidence, for example showing that the Commerce Commission has actually approved inefficient investments while the existing TPM has been in place. On the contrary, the EA's second issues paper shows that the six recent major transmission investments have generated large net benefits.[3]

18. Moreover, these three arguments are in effect the outcome of the EA's review of the existing TPM review. My review of expert reports submitted in response to the five separate consultation papers where these questions were mainly discussed (see section 3.2 below) shows no explicit support for the EA review's conclusions as they relate to investment planning or durability. Instead, eleven expert reports (from six distinct groups of experts) commented negatively on at least one of these aspects of the EA's diagnosis of

[2] Electricity Authority, Second Issues Paper, ¶5.5 – 5.8.

[3] Figure 38 on page 255 of the EA's second issues paper.

problems with the existing TPM. The following quote from PwC is an example: *"TPM does not have a material bearing on which investments are proposed or approved".*

19. In my opinion, based on the analysis discussed in this report, there remains an open question over whether there are serious problems with the existing TPM, and over the very significant changes currently being proposed by the EA. The absence of evidence that past investment has been inefficient is revealing, given the important role any such evidence would play, and the considerable effort the EA has devoted to this work over many years. It has not been established that the Commerce Commission's investment screening processes are deficient nor that they will be enhanced by the EA's proposals.

Distinction Between Guidelines and the TPM

20. Economic regulation of natural monopolies (such as Transpower) almost always involves a cap on total earnings, which we can think of as capping the overall *level* of prices. It is less common for regulators to dictate the *structure* of prices. Professor Yarrow's expert report attributes this distinction to the fact that the regulated firm (in this case Transpower) has incentives to design efficient prices, and a greater ability to do so than the regulator, because it has much better information about its customers.

21. These considerations may help explain why Parliament decided not to assign statutory responsibility for designing the TPM to the EA. Instead, the EA's statutory role is to issue guidelines to Transpower and assess its proposals. This set-up points to Transpower as the main developer of the TPM for review/contesting/approval by the EA, in a similar way to the capital investment process where Transpower does much of the analysis but the Commerce Commission has the final say.

22. Against this background, it is notable that the EA's proposed guidelines throughout this process have been very detailed indeed. The first issues paper in October 2012 proposed an extremely complex and detailed method for identifying the beneficiaries of transmission investments and estimating their benefits. The TPM Guidelines proposed in the second issues paper (May 2016) would also require extremely detailed disaggregation of the benefits of particular grid assets, while also obliging Transpower to design the estimation method. The most recent consultation paper, issued in December 2016 as a supplement to the second set of TPM proposals, proposes a further seventeen amendments to the guidelines, the general effect of which is to further reduce Transpower's discretion over the design of the TPM. I note that technical experts Scientia regard the task that Transpower would be obliged to undertake as difficult, highly sensitive to modelling assumptions and therefore very contentious. I agree with Scientia that the EA's latest proposals *"would require Transpower create a forecast of nodal prices, cleared generation and load quantities several decades into the future and use these forecasts as the basis for estimating private benefits"*.

23. The EA's rationale for proposing highly detailed guidelines is not clear. I note that the Electricity Industry Participant Code 2010, which governs the EA's guidelines and the TPM itself, provides at ¶12.79 that *"Transpower, in developing the transmission pricing methodology, and the Authority, in approving the transmission pricing methodology, must assess the transmission pricing methodology against the Authority's objective in section 15 of the Act"*. This section seems to permit the EA to ensure that all relevant objectives are met, even without the use of very detailed guidelines.

24. There is a further reason to query the very detailed nature of the requirements the EA is seeking to embed in the TPM Guidelines. As Professor Yarrow has noted, regulators of natural monopolies such as Transpower are concerned primarily with preventing the exploitation of market power through excessive charging, but frequently take the view that the regulated firm knows best how to design its charges. This is because the regulated firm (i.e. Transpower) interacts directly with its customers on a regular basis and therefore has superior information to regulators about the most efficient ways to earn revenue.

Relevance of New Zealand's Nodal Pricing System

25. A critical issue for the EA concerns the price signals that the TPM sends over the *location* of facilities that demand or supply electricity. Location decisions are investment decisions and therefore fall into the *"long-run"* category where dynamic efficiency is an important objective. The EA has referenced the risk of inefficient location decisions many times, starting from the development of its initial assessment framework in January 2012, indicating a strong concern for how investment responds to the TPM.

26. Reports from local experts have tended to take New Zealand's electricity pricing system as a given, whereas the international expert reports reviewed have more frequently emphasised the internationally unusual, and extremely efficient, nature of our electricity pricing. New Zealand sets over 250 different wholesale electricity prices, one for each "node" of the grid, every five minutes. These prices fully reflect the losses of energy that occur as power is passed through the grid, and the economic effect of grid constraints. The reason New Zealand went to the trouble/cost of having price differences between locations was to send efficient *locational* price signals for usage of electricity and investment in related equipment.

27. International experts, noting this unusual feature, have queried the EA's desire to pursue the next level of efficiency. One example is Compass Lexecon, who said: *"as long as nodal prices are properly set, both load and generators have the right signals to make efficient location decisions*". The relevance of New Zealand's system of nodal pricing (also known as locational marginal pricing or LMP) is also referenced by Bushnell and Wolak who disagree with the EA's view that the pursuit of beneficiaries-pay charges in some international jurisdictions offers support to the EA's proposals for New Zealand. Bushnell and Wolak note that under-investment in (particularly inter-state) transmission was a significant motivation for USA's use of beneficiaries-pay, whereas the EA's concern is excessive over-investment. Bushnell and Wolak also say: *"the perceived appeal of beneficiaries pay in other countries has been as much due to the absence of advantages present in New Zealand (e.g. the lack of LMP in the UK, or the overlapping jurisdictions in the US), as they are to the fundamental advantages of beneficiaries pay itself"*.

Can Beneficiaries Pay, and if so, How?

28. While some experts have expressed in-principle support for the idea of charging beneficiaries, others have emphasised the fact that benefits will inevitably change over time so any beneficiaries-pay charge (including the latest version, AoB) will become less

reflective of benefits over time.[4] Even setting aside these matters of principle however, experts have made compelling criticisms of the EA's proposals including over

a. practical challenges with identifying anything other than very broad groups of beneficiaries;

b. the long-term durability of any estimates of benefits as supply and demand patterns change; and

c. the lack of economic logic for retrospectively applying beneficiaries-pay charges to already existing assets.

29. The first two concerns are related because the benefits accruing to larger groups are likely to be more stable over time than dozens, or possibly hundreds, of node-specific benefit estimates. Moreover, relatively simple pricing systems such as a tilted postage stamp structure, under which prices broadly track average power flows, can also be a form of beneficiaries-pay. My review finds widespread expert opposition to the details of the EA's beneficiaries-pay proposals including the latest AoB version. There is evidence suggesting that it will be extremely difficult for Transpower to successfully comply with the proposed guidelines, and that the resulting pattern of charges will not be robust to small changes in modelling assumptions.

Existing or New Assets

30. Retrospective changes to liability for the cost of existing assets sit uneasily with some of the economic logic behind a beneficiaries-pay approach. The EA is strongly motivated by long-run considerations over the efficiency of major capital investments, particularly in grid assets. In arguing for a beneficiaries-pay approach, the EA relies heavily on the view that the Commerce Commission will be less likely to approve inefficient grid investments if there is a form of user-pays for those investments (i.e. beneficiaries-pay or area-of-benefit (AoB) charging). This is a *long-run* argument, concerning *dynamic* efficiency.

31. Yet the EA's proposals since 2012 have consistently included old, pre-existing assets, in the set of costs that should be allocated to beneficiaries. This is difficult to understand, even if one accepted the EA's theory that the Commerce Commission's decisions are vulnerable to self-interested lobbying.

32. The expert reports challenge the EA's view that re-allocating liability for costs already incurred can lead to more efficient future investment decisions. PwC advocated *"avoiding the retrospective reallocation of sunk costs"*. Compass Lexecon said: *"as long as these charges are applied to existing assets, the proposal fails to implement the minimum distortion principle for sunk cost recovery"*. CEG said: *"there can be no dynamic efficiency benefits associated with applying a 'beneficiaries pay' approach to reallocating the sunk costs of past investments"*.

33. I agree with these authors and other experts who made similar points. There are also static efficiency costs from the inclusion of pre-existing assets, including the somewhat

[4] Bushnell and Wolak use the HVDC link to make this point. They view the separate HVDC charge as an early experiment with beneficiaries-pay charges and note that the perceived beneficiaries have changed since this charge was implemented.

perverse effect that electricity consumers in the north of New Zealand will experience higher transmission charges (which will deter some electricity consumption), because of recent investment that has eased transmission constraints: so transmission prices will rise even though the short-run costs of transmission have fallen.

1.2 Framework Propositions

34. In this section I summarise the expert opinion on five propositions relating to the analytical framework used by the EA in its TPM reform process.

1.2.1 Reasonable and appropriate decision-making framework

The economic decision making framework used by the EA to review the current TPM and select options for reform of the TPM Guidelines is reasonable and appropriate.

35. My review of the expert reports identified one report that endorsed this proposition (NZIER) while five criticised the EA's decision making and economic (DME) framework itself, and another four criticised its application.

1.2.2 Compelling evidence of a problem

There is compelling evidence that one or more problems exist.

36. The TPM review process began with the EA defining problem(s) with the existing TPM as including the absence of its preferred solution. This approach does not facilitate a broad search for solutions, and creates a risk that any changes implemented will be less than fully beneficial. While the problem definition was sharpened somewhat as the review progressed, substantial criticisms remained. Over time, arguments against the evolving problem definition focussed more heavily on the EA's description of the interconnection charge problems and the durability problems, and on the EA's estimates of the scale and materiality of problems.

37. My review identified fifteen expert reports that commented on the proposition at issue: fourteen were clearly in disagreement while one was equivocal.

1.2.3 CBA identifies costs, risk and benefits in a robust manner

The EA's cost benefit analysis identifies and assesses the costs, risks and benefits in a robust manner.

38. In my opinion, the expert evidence suggests that the proposition at issue is false: neither of the cost benefit analyses has assessed the costs, risks and benefits of the EA proposals in a robust manner. This calls into question the veracity of both the scale of the problems with the existing TPM claimed by the EA, and the benefits of replacing the TPM Guidelines.

1.2.4 AoB charge will send desired price signals

The EA has established than an AoB charge will send desired price signals.

39. There was widespread expert opposition to the proposition that the EA's proposed AoB charge will send desired price signals. It related primarily to the practical challenges in sending the desired price signals, rather than to the principle of charging beneficiaries *per se*. Experts noted that attempts to precisely identify beneficiaries and estimate their benefits would inevitably be complex and contentious, that the AoB charges will change as new investment is installed and that, even without investment, changing patterns of usage will make AoB charges less accurate over time.

40. There have also been repeated detailed challenges from experts arguing that beneficiaries will be unable to reliably estimate the way their charges will change in response to particular new investments. These concerns undermine the potential for AoB charges to guide market participants and final electricity consumers toward efficient conduct.

1.2.5 AoB charge is superior to the alternatives

The AoB charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and tilted postage stamp.

41. The proposition assessed in this section was "that the area-of-benefit (AoB) charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and the tilted postage stamp". In reviewing the expert reports that bear on this proposition, I have widened its scope to include a broader range of comment. I have identified and cited thirty-four expert reports (submitted in response to four EA consultation papers) that are informative as to the authors' views on the proposition.

42. Two of the thirty-four expert reports reviewed explicitly stated that an EA proposal was superior to the status quo: NERA's response to the first issues paper in 2012 (see ¶212.f), and Stephen Littlechild's response to the second issues paper in 2016 (see ¶223). I note that on the second issues paper, NERA were among others (EPOC, Castalia, Compass Lexecon) in offering *in principle* support for an AoB charge, while advocating changes to the EA's proposals for this charge.

1.3 Expected Outcomes

43. In this section I summarise the expert opinion on seven propositions relating to the likely outcomes in the event that the EA's proposed changes to the TPM Guidelines are implemented.

1.3.1 Guidelines Promote Long Term Benefits

The proposed guidelines are likely to promote long-term benefits for electricity consumers.

44. The expert reports weigh heavily against the proposition that the EA's proposals are likely to promote long term benefits for electricity consumers. Only one of the fifteen expert reports commenting on this proposition expressed support.

1.3.2 Improved Efficiency of Generation and Load Investment

> *The proposed guidelines are likely to materially improve the efficiency of future investments in generation and load.*

45. None of the expert reports I reviewed expressed clear support for the proposition that the EA's proposals are likely to materially improve the efficiency of future investments in generation and load. One report offered limited support, while seven reports clearly disagreed.

1.3.3 Improved Efficiency of Transmission Investment

> *The proposed guidelines are likely to materially improve the efficiency of future investments in transmission.*

46. The weight of expert opinion is strongly against the proposition that the EA's proposals are likely to materially improve the efficiency of future investments in transmission. Of the ten expert reports that expressed a view on the proposition, only one was in partial support. I also note that NERA's first report appeared to disagree, despite NERA's overall support for proposal described in the EA's first issues paper.

1.3.4 Reduced Distortions in Grid Use

> *Distortions (i.e. inefficiencies) in grid use under the existing TPM will be eliminated or materially reduced.*

47. I found ten expert reports that expressed a view on this proposition: all were in disagreement.

1.3.5 More Durable

> *The proposed guidelines will be more durable than the status quo.*

48. Ten expert reports commented on whether the EA's proposals would result in a more durable TPM: eight disagreed; two agreed.

1.3.6 No Unintended Consequences

> *There are no unmanageable or unacceptable unintended consequences likely to arise from an area of benefit (AoB) charge.*

49. Ten expert reports were identified as commenting on whether there are likely to be material unintended consequences arising from the EA's proposals: all ten saw risks of material unintended consequences.

1.3.7 Consistent with International Best Practice

The proposed approach is consistent with international best practice.

50. I found no support in the expert reports for the proposition that the EA's proposals are consistent with international best practice: five expert reports were identified as commenting negatively on this proposition.

1.4 Details of TPM Proposals

51. In this section I summarise the expert opinion on seven propositions relating to particular details of the EA's proposals to change its TPM Guidelines.

1.4.1 Reasonable Selection of Assets for AoB Charge

The selection of a subset of interconnection assets (including the HVDC assets) for inclusion in the AoB charge is a reasonable approach and/or will result in improved efficiency and/or more equitable outcomes.

52. My review of the expert reports submitted since 2012 shows twenty expert reports opposing the EA's proposal to include assets installed since 2004 in the AoB charge, with two in favour: Professor Littlechild and NERA's second report. For reasons explained in the body of this report, I consider that neither of the two supporting expert reports provides a convincing argument in support of the proposition.

1.4.2 Accurate Assessment of Beneficiaries

There is a mechanism for accurately assessing the lifetime beneficiaries of shared assets

53. Since the first issues paper was published, I found twenty-two expert reports that disagreed with this proposition and none that agreed. The only two submissions on the second issues paper that broadly supported the EA's proposals both disagreed with this proposition.

1.4.3 Fixed Capacity Measure is Appropriate for AoB and Residual Charges

The default allocation method for the AoB charge and the allocation method for the residual charge should be based on a measure of fixed capacity

54. Expert opinion was generally against this proposition, though it was not extensively commented upon. I found five expert reports opposed, and none in support.

1.4.4 Cost Allocators are Appropriate

It is sensible and consistent with the EA's statutory objectives to remove the RCPD charge

55. Expert opinion was generally against this proposition, though it was not extensively commented upon. I found six expert reports opposed, one uncertain, and one in support.

1.4.5 Appropriate to Include DER in Capacity Assessment

The inclusion of DER in the capacity assessment for the residual charge is appropriate.

56. I only found two expert reports that commented on this proposition, both in response to the second issues paper. Both of these reports disagreed with the proposition.

1.5 Conclusion

57. This review has left with me the strong impression that the EA has not been heavily influenced by the criticism these experts have made of its proposals. While there have been many consultation papers since the first issues paper, and the EA's proposals have changed over that time, the original firm commitment remains to eliminating the HVDC charge and introducing a node-based beneficiaries-pay charge for all new assets and a subset of existing assets. In the face of strong and detailed criticism from many different experts, the EA has modified its proposals, shifting wealth around between different participants, but never deviating from these two consistent goals, neither of which emerged from a disciplined policy development process.

58. Expert opinion weighs very heavily against the EA, including on critical framework propositions such as that the AoB charge will send desirable price signals, that it is the best available option, and that it will promote the long term benefit of consumers.

59. Table 1 below summarises the propositions assessed and the number of expert reports that agree and disagree with each. Expert opinion weighs heavily against the EA confirming its proposed TPM Guidelines.

60. Finally, it is worth noting that the extent of expert engagement with the various consultation papers has varied (see Appendix 1) and some expert reports have been deliberately focussed on particular issues (e.g. the cost-benefit analysis). This variation is likely to partly reflect other constraints acting on interested parties at the consultation times. For example, at the time of the second issues paper consultation, many electricity network businesses were simultaneously working on submissions to the EA's distributed generation pricing reform and to the Commerce Commission's review of input methodologies.

Table 1: Summary of Expert Views on Propositions

Proposition	Agree	Disagree
Reasonable decision making framework	1	9
Compelling evidence of a problem	0	14
CBA is robust assessment of costs, risks and benefits	1	14
AoB charge will send desirable price signals	0	12
AoB charge is superior to alternatives	0	32
Promote long-term benefits for consumers	1	14
More efficient load and generation investment	1	8
More efficient transmission investment	1	9
More efficient grid use	0	10
More durable TPM	2	8
No unintended consequences	0	10
Consistent with international best practice	0	5
Selection of assets for AoB charge is reasonable	2	20
Mechanism exists for assessing beneficiaries	0	22
Fixed capacity reasonable measure for allocating interconnection costs	0	5
Cost allocators are appropriate	1	6
Appropriate to include DER in capacity for residual charge	0	2

2 Introduction

62. This report is based on my review of sixty expert reports submitted to the Electricity Authority (EA) since its first issues paper in October 2012, which reviewed the current transmission pricing methodology (TPM) and proposed replacement TPM Guidelines. The report was commissioned by counsel acting for Trustpower. It represents my own views as an independent expert. I have read and agree to be bound by the High Court's code of conduct for expert witnesses. The matters covered below fall within my area of expertise. My qualifications for this assignment are appended below.

2.1.1 Background

63. The high voltage national grid is owned and operated by Transpower, which is in turn regulated by two official agencies. The Commerce Commission is charged with setting the maximum revenue Transpower is permitted to earn in each time period, and screening Transpower's major investment projects, for which purpose it uses cost-benefit analysis (CBA). The maximum allowed revenues are then recovered by Transpower through a set of prices calculated in accordance with the TPM. A different regulator, the Electricity Authority (EA), is responsible (among other things) for setting *guidelines* for the TPM.

64. There is a strong economic motivation for this bifurcation in regulatory roles. The regulation of natural monopolies such as Transpower is generally focussed on ensuring they do not earn excessive financial returns. Parliament reformed New Zealand's monopoly regulation laws in 2008 through Part 4 of the Commerce Act. These amendments obliged the Commerce Commission not just to regulate natural monopolies in the public interest, but also to pre-commit itself to the methods it would use in doing so. As a consequence, the Commerce Commission developed very detailed *"input methodologies"* which were subject to (and largely survived) extensive merits review in the High Court.

65. While the *level* of a natural monopolist's revenues is an obvious matter of public interest, once that level is regulated (as it now is for Transpower), the *structure of prices* used to earn that revenue is very much a secondary concern. For example, prior to the UFB initiative, Telecom had a natural monopoly over phone-line connections in New Zealand. The policy response was to regulate in ways that sought to prevent that monopoly from distorting retail competition, but the Telecommunications Act has never allowed for regulation of retail price *structures*. Drawing on wide international experience, Professor George Yarrow acknowledged a diversity of regulatory approaches to price structure and concluded that

> *"the centre of gravity of approaches adopted in practice can be said to be characterised by the granting of significant discretion to a regulated firm in respect of its choice of price structure"*

66. The economic motivation for allowing discretion over price structures is that regulated firms have much better information about demand than regulators, because they are facing customers on a daily basis. Transpower is well aware that it faces a demand curve: if prices get too high, customers will seek to minimise grid usage and/or use alternative resources (such as localised, distributed generation) which are becoming increasingly

attractive in the electricity sector. The natural response of Transpower to such pressures is also economically efficient: it should, and will, pursue the principles of Ramsey pricing: designing a price *structure* that recovers revenue from services in inverse proportion to the elasticity of demand for the service.[5]

67. For most electricity customers, transmission pricing is not paid directly to Transpower, however, but to a retailer. While retail tariffs do generally include a fixed daily charge, these fixed charges are too low to recover all fixed costs, and the corresponding per-unit tariffs are therefore higher than would be consistent with Ramsey pricing. The low-user pricing scheme, designed to allow some users to choose even lower daily charges in return for higher usage tariffs, is even further from away from Ramsey pricing.

68. The current split of regulatory roles in electricity is, broadly, that the Commerce Commission is responsible for the natural monopoly issues: ensuring that lines companies (including Transpower) do not over-charge or over/under-invest; while the EA is responsible for the structurally competitive parts of the sector. Under this arrangement, the EA is responsible for the efficient operation of the wholesale market and promoting retail competition.

69. The matter at hand appears to have arisen from the EA deciding that the *structure* of transmission prices (the TPM) has been, and/or might in future be, biasing the Commerce Commission's assessment of Transpower's investment proposals. The mechanism envisaged is that market participants and end-users are not facing the full cost of their actions, so they behave inefficiently, leading to inefficient patterns of grid investment. There are many references in the EA's publications to the incentives various persons have to advocate or oppose particular transmission investments. Open questions nevertheless remain over whether such lobbying has affected the Commerce Commission's decisions and/or is likely to do so, and over whether the proposed changes to the TPM will improve matters. On this latter point, it has been noted by experts that the location of significant investments by electricity users (load) are often made primarily with reference to the location of inputs or customers; transmission charges are of secondary importance.

2.2 Regulatory Initiatives

70. In regulating Transpower's investment programme and annual revenue, the Commerce Commission is obliged by Part 4 of the Commerce Act (s52A(1)) to act in ways that:

> *promote the long-term benefit of consumers … by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—*
>
> a. *have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and*

[5] Ramsey pricing theory emerged from the economics of taxation. Its formal development was already intuitively attractive to Jean-Baptiste Colbert, Louis XIV's Minister of Finance, who said that *"the art of taxation consists in so plucking the goose as to obtain the largest possible amount of feathers with the smallest possible amount of hissing."*

b. *have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and*

c. *share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and*

d. *are limited in their ability to extract excessive profits*.

71. In January of 2012 the Commerce Commission published a Capital Expenditure Input Methodology Determination for Transpower[6], describing in detail the methods it would use to assess Transpower's capital investment proposals, and (separately) its reasons for adopting these input methodologies.

72. In October 2012,[7] the EA consulted on its review of the TPM Guidelines and its proposal for major changes to the existing guidelines. In doing so, the EA referenced (at ¶2.1.1) its own objective under s15 of the Electricity Industry Act 2010, which is to "*promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*" and s12.78 of the Code concerning the purpose for establishing the TPM. The regulatory objective (s12.79) of the Code is also relevant. It states

> *Transpower, in developing the transmission pricing methodology, and the Authority, in approving the transmission pricing methodology, must assess the transmission pricing methodology against the Authority's objective in section 15 of the Act.*

73. This regulatory objective suggests that quite broad and/or general guidelines could be used, as both Transpower and the EA are bound by the Code to pursue the objective stated in s15 of the Act.

2.2.1 Consequences of the First Issues Paper

74. The EA's review of the TPM and proposals for major changes to its TPM Guidelines was not well received by those responding to the consultation. The apparent outcome of the review effectively became the problem definition for analysing change options. There were three main concerns expressed: that the TPM does not establish efficient prices (though the EA does also note that there is no perfect TPM); that the existing HVDC and interconnection charges are inflexible and not durable; and that beneficiaries should pay.

75. Twelve expert reports were submitted in response, none were uncritical and only one endorsed the proposed changes as being superior to the status quo.

76. The EA never explicitly withdrew its proposal, nor did it finalise its review of the TPM. Instead, it spent the next few years publishing a sequence of further consultation documents, each of which investigated one aspect of the broader question of TPM reform.

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[6] http://www.comcom.govt.nz/dmsdocument/6751

[7] Electricity Authority, Transmission Pricing Methodology: Issues and Proposal, Consultation Paper, 10 October 2012.

A second full proposal for change, which was also described as being part of the TPM review, was published by the EA in May 2016[8] and a further set of supplementary proposals was published in December 2016.[9]

77. Throughout this period, a very large number of submissions have been supplied to the EA. A major purpose of this report is to review the submissions supplied to the EA by experts (as distinct from market participants, end-users and other stakeholders). There are sixty such submissions (see Appendix 1 for a full list of these expert submissions). To help characterise this large body of material, I will assess the extent to which each of them agrees or disagrees with a list of propositions, and will seek to draw out general themes while noting dissent from those themes.

78. In the balance of this introductory section I will briefly summarise the existing TPM and its relationship with the pricing of electricity in New Zealand. The EA's two main reform proposals will then be described and I will comment on their similarities and differences.

2.3 Current Transmission Pricing Arrangements

79. The high voltage grid connects electricity generation stations to some large directly-connected users of electricity, and to low voltage distribution networks that convey electricity to all other end-users. There are over 250 "nodes" of the grid: power is injected by generators at 59 nodes and taken off the grid at the other 226 nodes.

80. Power is priced using a sophisticated method by international standards known as "nodal pricing", whereby at any given time the price of electricity is different at each grid node. These nodal price differences signal the cost of electricity at each location, which varies due to line losses and network constraints. Since the electricity pricing system estimates the *marginal* cost of electricity at each node, and marginal losses and constraints exceed average losses and constraints, this pricing method generates a surplus of cash, known as the "*loss and constraint excess*". This surplus is distributed to offtake customers.

81. The use of the transmission grid is priced through the TPM in a relatively simple manner based on three charges:[10]

   a. Connection charges are paid by each party directly connected to a node. These are used to recover the cost of Transpower's assets at each node.

   b. The cost of the high voltage direct current (HVDC) link connecting the North and South Islands is charged to generators located in the South Island.

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[8] Electricity Authority, Transmission Pricing Methodology: Issues and Proposal, Second Issues Paper, 16 May 2016.

[9] Electricity Authority, Transmission Pricing Methodology: Issues and Proposal, Second Issues Paper, Supplementary Consultation, 13 December 2016.

[10] The historic development of the TPM is described in Appendix B of the Electricity Authority's first issues paper, and in Bruce Girdwood, Transmission Pricing, Regulation and Practice, A Practitioner's View, 23 July 2016.

c. All other costs are recovered from offtake (load) customers through an "interconnection" charge. These costs are allocated between nodes in proportion to a measure of peak demand.

82. The interconnection charge is set on the basis of regional co-incident peak demand (RCPD), which by definition involves the aggregation of nodes. Four regions were defined, and the RCPD for each region are currently determined by examining the 12 peak demand periods for the upper North Island (UNI) and upper South Island (USI) regions, and 100 peak demand periods for the lower regions of both islands (LNI, LSI). However, from 1 April 2017 all regions will use 100 peak periods, following a TPM change initiated by Transpower in 2015. It has been noted by experts that the strength of the RCPD price signal varies with the number of peaks included: the signal is sharper/stronger when fewer peaks are included.

83. The HVDC charge is currently set for individual generators on the basis of their historic anytime maximum injection (HAMI) over the last five years. From 1 April 2017 this charge will transition, over a four-year period, to a charge based on South Island mean injection (SIMI).

84. Both of these allocation methods (RCPD for interconnection and HAMI/SIMI for the HVDC charge) have been designed in part with the objective of discouraging changes in behaviour.[11]

85. In the year to March 2016, the connection charges recovered 14% of Transpower's total allowable revenue, the HVDC recovered 16% and the remaining 70% was recovered through the interconnection charge. The total amount recovered through the TPM was $917m.

2.4 Proposals for Change

86. I now outline the two EA proposals for changing the TPM Guidelines. In advancing these proposals, the EA has appeared to be motivated primarily by a desire to improve the efficiency of capital investment in the grid, and in facilities that affect grid traffic.

2.4.1 First Issues Paper – October 2012

87. In its first issues paper, the EA proposed:

a. removing the HVDC and interconnection charges;

b. re-allocating the loss and constraint excess to Transpower;

c. introducing a new asset-based "*beneficiaries-pay charge*" on load and generation which would "*shift over time with changes in grid use and configuration*"; and

[11] Responding to the second issues paper, Bruce Girdwood notes that this has been an objective since the 1990s. "*A TPM should allocate the fixed costs of owning and operating the grid in way that reflects the nature of those cost – i.e. to the extent practicable, fixed and unavoidable*"

d. collecting the balance of Transpower's revenue using a "residual" charge, which would be levied in a similar way to the existing interconnection charge except that the revenue to be collected would be split 50:50 between generators and offtake customers.

88. The beneficiaries-pay charge for a particular grid asset was intended to recover the cost of that asset, rather than the total benefits it delivered. However, total benefits need to be estimated to determine the proportion of the cost allocated to different beneficiaries. The EA proposed that benefits would be estimated by simulating the nodal prices that would have emerged if that asset were not present, and comparing these with observed market outcomes when the asset was present (i.e. the focus was on prices in the past). The algorithm used to set half-hourly nodal prices for electricity would be used for this purpose. The EA estimated that the loss and constraint excess would recover 5% - 20% of Transpower's costs, the beneficiaries-pay charge would recover 30% - 60% and the residual charge would recover 5% - 50%.[12]

89. The EA proposed that all grid investments in excess of $2m that were made since 28 May 2004, plus pole 2 of the HVDC link, would be priced using the new TPM and hence subject to a beneficiaries-pay charge, with the cost of all other assets being recovered through the residual charge (which was to be split 50:50 between load and generation). Over time, as new assets were added, the impact on transmission prices of these legacy assets would diminish.

90. This proposal attracted strongly negative feedback. Important categories of criticism from the expert reports included the following:

a. Problem definition. Experts noted that the EA had described the problem it was trying to address as the absence of the EA's preferred solution (asset-based beneficiariespay). This suggested that beneficiaries pay (in the form proposed by the EA) had not emerged from a disciplined policy analysis process.

b. Sunk costs. Experts argued that retrospective reallocation of the costs of existing assets would not help to make new investment decisions more efficient, and would provoke further disputes.

c. Practicality. Experts argued that there would be severe practical challenges in implementing the proposed guidelines. One reason cited was that the interconnected nature of the grid means that power flows (and the nodal spot prices of power) are created by the interaction of demand and supply of all market participants and end-users. Another was that power flows change very frequently, whereas the grid assets last several decades, so using the former to recover the costs of the latter will inevitably require assumptions to be made about the uncertain future patterns of grid usage.

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[12] First issues paper, figure 6, page 75.

d. Cost benefit analysis. Experts were strongly of the view that the EA's cost-benefit analysis was deficient. The dynamic efficiency benefits of the proposal were not estimated, but instead amounted to an assumption about the scale of benefits.

91. In response, the EA neither implemented nor withdrew the proposal. Instead the EA began issuing further consultation papers dealing with subsets of the TPM development process, such as cost-benefit analysis, sunk costs, different ways to design beneficiaries-pay charges, and the problem definition.

2.4.2 Second Issues Paper – May 2016

92. In the second issues paper, the EA proposed a different version of beneficiaries-pay, known as an area-of-benefit (AoB) charge. This charge was still based on the concept of allocating individual assets, rather than asset groups. The three main tariff changes proposed were:

a. removing the HVDC and interconnection charges;

b. introducing a new "*area-of-benefit charge*" on load and generation to recover the cost of "*eligible interconnected grid assets*"; and

c. collecting the balance of Transpower's revenue using a "residual" charge which would be based on capacity (i.e. the maximum possible usage) rather than usage and levied on offtake customers only.

93. The EA proposed to use the AoB charge to recover the cost of all new grid investments, plus pre-existing assets costing more than $50m that were approved after May 2004, plus pole 2 of the HVDC link. An area-of-benefit was defined by the EA as *"an area in which at least one designated transmission customer is expected to receive a positive net benefit from the eligible investment"*. The requirement to estimate benefits in such small areas makes the proposed charging regime very complex. Further, the EA proposed that the guidelines would require the charges to be based on *forecasts* of the lifetime benefits of each asset and the share of those benefits to be allocated to each grid user. Once estimated, the resulting charges would be fixed. In particular, they would not change if patterns of grid usage (and hence benefits) differed systematically from the patterns originally forecast.

94. Rather than specify a method for determining how to assess the private benefits of each grid user in relation to each grid asset, the EA proposed that Transpower be responsible for this task. The EA also proposed to require that Transpower develop both "*standard*" and "*simplified*" methodologies, and that it follow EA guidance on the valuation of assets.

95. The costs of all other non-connection assets were proposed to be recovered through the residual charge. The EA stated an expectation that the residual charge was expected to recover *"around $500 million per year initially"* which represents most of the almost $800m of the total annual cost of non-connection assets. Over future decades, the proportion of total funds recovered through the residual charge would slowly fall.

96. In addition, the EA proposed two methods by which grid customers could seek to have their total transmission charges reduced:

a. An expanded prudent discounting policy (PDP) that would discount charges to retain offtake customers that might otherwise disconnect from the grid, either to close down operations or use stand-alone local generation as an alternative to the grid; and

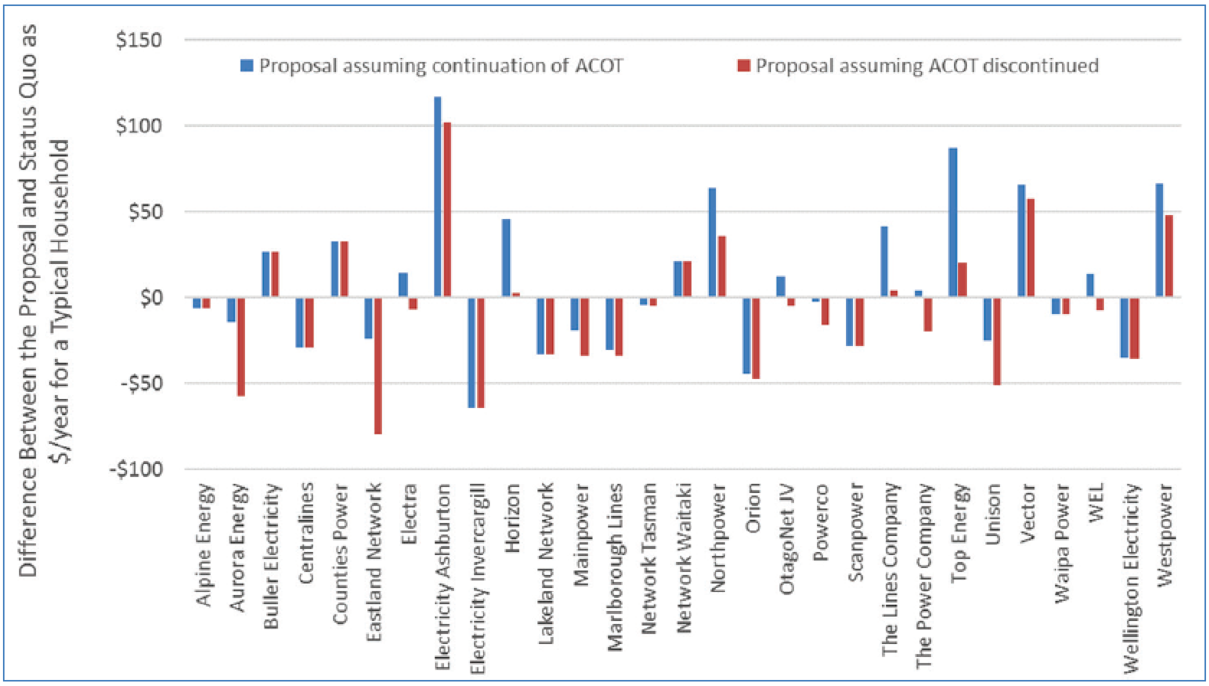
b. A right of appeal to Transpower against area-of-benefit (AoB) charges in respect of assets for which usage has materially declined.

97. Regarding the asset valuation issues (see ¶94 above), the EA's second issues paper proposed valuation methodologies for Transpower's assets that are materially different to those used to regulate Transpower's total earnings. Under the input methodologies developed pursuant to Part 4 of the Commerce Act, the value of Transpower's assets is fixed except for additions (via new investment) and subtractions (via depreciation). The EA proposed that, for pricing purposes, existing assets would be valued at their depreciated historic cost (DHC) and that new assets be valued at their replacement cost (RC). Moreover, the EA proposed to *"require the TPM include a method and process for optimisation of assets in high value investments"*. Replacement cost valuations and asset value optimisation were used by Transpower (and electricity distribution companies) before the Commerce Commission determined input methodologies in 2010, but since that time these methods have not been relevant to the setting of regulated caps on earnings.

98. The proposal included the EA's estimates of how the proposed changes would affect the transmission component of a typical household in each distribution network's area. These estimates are reproduced in Figure 1 below.[13]

[13] Note however that these estimates appear to be based on the EA's estimates of benefits in one year (2019) whereas the proposed TPM requires estimates of lifetime benefits. See ¶192 of the second issues paper.

Figure 1: EA's Estimate of Proposed TPM Changes on Typical Households



2.4.3 Supplementary Proposals December 2016

99. In its supplementary proposals, the EA expressed the view that the *"proposed TPM charging framework is fundamentally robust"*, referring to the framework proposed in the second issues paper. A further seventeen changes were nevertheless proposed, including to the PDP, the valuation of assets and the optimisation process.

100. In general, the supplementary proposals have the effect of tightening the TPM Guidelines by reducing Transpower's discretion over particular issues. A good example is the proposal at ¶15(e) of the supplementary proposal, which is that the EA seeks to insert into the TPM Guidelines:

> *"a method to provide a proxy for calculating the AoB charge, if calculating it would be otherwise impracticable, and a method to scale back the charges for the residual charge, overhead and unallocated expenses and the AoB charges on investments made before the publication of the proposed guidelines, if that is necessary to avoid over-recovery of Transpower's revenue"*

101. This is in fact two proposals. The first seeks to ensure that an approximation to an AoB charge is still used, even if the actual AoB charge provided for elsewhere in the guidelines proves to be impracticable for Transpower to implement. Secondly, Transpower will not have the discretion to scale back certain charges if it turns out that the TPM Guidelines would lead to over-recovery of Transpower's costs; instead, the EA will specify precisely how this scaling process will be undertaken.

2.5 Comparison of EA's Proposals

102. These proposals, in the first issues paper and in the second and supplementary issues papers, have the following common features:

a. elimination of the existing distinct charge on South Island generators for the HVDC link;

b. very granular estimation of the benefits provided by individual assets in the interconnected grid, and the allocation of those benefits to small groups of customers in proportion to their estimated share of the benefits; and

c. re-allocation of the costs of existing grid assets (again calculated on an asset-by-asset basis) for which investment was approved during or since 2004.

103. Their main differences are that:

a. In the second proposal, the estimation and allocation of benefits for each individual grid investment changed from being based on past nodal prices to future nodal prices, and Transpower was required to develop the methods;

b. the residual charge was initially split 50:50 between load and generation, but is fully allocated to load in the second proposal; and

c. the second proposal includes "escape clauses" that would transfer cost obligations from those with opt-out options to those without such options.

104. The main proposals for change (2012 and 2016) appear to represent three common themes in the EA's thinking. First, the EA considers that the efficiency of *future* grid investments will be enhanced by focussing the obligation for transmission charges on those expected to benefit from those new grid investments. Both proposals have this feature, and in advancing them the EA has referred to its concerns that a TPM that embodies a high degree of averaging costs across all users (e.g. through the existing interconnection charge) creates incentives for self-interested lobbying for particular upgrade projects. In theory, such lobbying could result in inefficient grid investments because the parties promoting them would know that many of the costs of the investments would be borne by others. However, in practice, the Commerce Commission has control over investment and is highly experienced in distinguishing between lobbying based on private interests and evidence relevant to its statutory obligations.

105. A second common theme is that incentives for efficient *future* grid investments will be enhanced by focussing the obligation for TPM charges on those who have been deemed to benefit from *previous* grid investments. This theme is inferred from the fact that both proposals re-allocate the costs of all major grid investments since May 2004, and all of the costs of the existing HVDC link, towards those parties deemed to benefit from them.

106. The third theme is that a highly granular estimation of benefits is required. Transpower's customers are the beneficiaries of its investments and they do already pay for them. In this sense beneficiaries are already paying. However, the EA has consistently found that the existing TPM does not meet its definition of beneficiaries-pay and sought a much more granular approach. This increases complexity and cost, but there has been no attempt by the EA to assess the optimal level of granularity.

2.6 Structure of this Report

107. I will begin by assessing the extent to which each author (or group of authors) agree or disagree with a set of propositions. This work is presented in the following three sections:

a. Section 3 examines propositions concerning the analytical and decision-making framework used by the EA;

b. Section 4 is based on propositions about the expected outcomes from the recommended options; and

c. Section 5 draws on propositions about a set of detailed features of the proposals.

108. Finally, in section 6, my conclusions are described in the form of a summary of the way the expert opinion has affected the EA's work on the TPM over the last four years.

3 Framework Issues

109. It is generally agreed that analysis by regulators that supports intervention in markets should be rigorous and complete. Most guidance of sound regulatory practice contains principles against which the quality of regulatory work can be assessed. For example, the UK's Better Regulation Commission proposed five principles as follows: [14, 15]

- **Proportionality**. Regulators should intervene only when necessary. Remedies should be appropriate to the risk posed, and costs identified and minimised.
- **Accountability**. Regulators should be able to justify decisions and be subject to public scrutiny.
- **Consistency**. Government rules and standards must be joined up and implemented fairly.
- **Transparency**. Regulators should be open, and keep regulations simple and user-friendly.
- **Targeting**. Regulation should be focussed on the problem and minimise side effects.

110. Below the level of principle, it is normal to expect that regulators define clear objectives, provide evidence of the problems they are addressing, use a robust and transparent decision-making framework, and carefully study the costs and benefits of intervention options. With these norms in mind, I have reviewed the expert reports against the following "framework" propositions:

a. The economic decision-making framework used by the EA to review the current TPM and select options for reform of the TPM Guidelines is reasonable and appropriate;

b. The regulatory objective is clearly defined and sound;

c. There is strong evidence that one or more problems exist;

d. The EA's cost-benefit analysis of its proposed TPM Guidelines identifies and assesses the costs, risks and benefits in a robust manner;

e. The EA has established that an AoB charge will send desired price signals;

f. The AoB charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and tilted postage stamp.

[14] http://www.eesc.europa.eu/?i=portal.en.self-and-co-regulation-literature.3257
[15] Similar work has been published by the New Zealand Treasury in 2012 (http://www.treasury.govt.nz/economy/regulation/bestpractice/bpregmodel-jul12.pdf) and by the OECD (http://www.oecd.org/fr/reformereg/34976533.pdf)

111. In examining these propositions, for the reasons explained above (¶104) I treat the initial (October 2012) beneficiaries-pay charge as an AoB charge.

3.1 Economic Decision-Making Framework

112. The proposition evaluated in this section is that

> *The economic decision making framework used by the EA to review the current TPM and select options for reform of the TPM Guidelines is reasonable and appropriate.*

113. The decision making and economic framework (known as the DME) used by the EA is said to be based on its statutory objective (Electricity Industry Act, 2010, s15) which is "*to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers*". In the first issues paper, and in its earlier (January 2012) consultation paper on the decision making and economic framework for the TPM review, the EA interpreted this objective (¶3.2.2) as requiring it to "*focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers*".

114. This approach conflates the three limbs of the statutory objective into just one objective, raising an obvious question as to why Parliament did not adopt this simpler wording in the Electricity Industry Act 2010. George Yarrow's report addresses this question, outlining "*the three main reasons why delegated regulatory objectives are not expressed, simply and flatly, as 'ensure long-term economic efficiency'*". Paraphrasing, those reasons are that:

a. Regulatory accountability would be materially reduced because the impact of regulatory decisions on long-term efficiency, "*being largely unknown, are necessarily speculative or subjective*";

b. It would be a "*vast and infeasible task*" to "*require a regulator to take account of effects in all economically related activities*" as would be implied by an overall efficiency objective; and

c. As conventionally assessed, an overall efficiency objective would pay "*no heed to the distribution of economic benefits from exchange transactions, whereas policy objectives almost invariably encompass distributional considerations*", which are included in s15 of the Electricity Industry Act through its reference to the long-term interests of consumers.

115. Relying on its re-phrasing of the statutory objective, the EA then set out (¶3.3.1) a hierarchy showing its preferred ranking of different types of charges as follows:

a. market-based charges;

b. exacerbators-pay charges;

c. beneficiaries-pay charges; and

d. alternative charging options.

116. In applying this framework, the EA determined in its first issues paper that neither of the first two options were feasible, so it focussed on beneficiaries-pay at the level of individual assets. Most experts commenting on the first issues paper did not seek to re-open discussion on the merits of this framework, and were therefore silent on our first proposition. The exceptions were:

a. Castalia, who stated "*the Authority's framework for decision-making, while useful, is too high a level to enable detailed and meaningful comparison of TPM alternatives and design choices*";

b. CEG who criticised the application of the framework saying "*rather than picking a single option, the EA attempts to 'take what it can' from each option, before moving to the 'next rung' in the ladder. The resulting methodology therefore contains a collection of different pricing principles*";

c. NZIER, who, while critical of the proposal overall was the only expert to explicitly endorse the framework stating that "*the decision-making and economic framework decided in 2012 is, however, still sound*"; and

d. Redpoint, who cited four other frameworks, including two previously used in New Zealand, noting "*these principles had been in the Code (and the previous Electricity Governance Rules) for many years. We understand that, following consultation, the EA removed these principles in favour of any TPM proposed and developed being assessed against the EA's statutory objective.*"

3.1.1 TPM Options Working Paper

117. The next reference to the DME appears in the TPM Options working paper,[16]where the EA (¶3.20) notes opposition to the DME.

> *Some parties submitted that the Authority should abandon the DME framework. Submitters were concerned that the DME framework was being used by the Authority to justify or pre-determine a preferred option, and that the continued use of the DME framework was an unnecessary and unhelpful constraint on the Authority's thinking and process.*

118. The EA (¶3.21) rejected this criticism and proceeded to use the DME in assessing TPM options. In response:

a. James Bushnell criticised the DME itself, arguing that it could be inconsistent with promoting dynamic efficiency, and the EA's application of the DME on the basis that "*the proposed Deeper Connection and LRMC charges are, in important ways, neither market-like nor dynamically efficient*";

[16] Electricity Authority, Transmission Pricing Methodology Review: TPM Options Working Paper, 16 June 2015.

b. Castalia argued that while the DME helps identify options it does not help to evaluate them, and that *"the "waterfall" approach that results from a strict application of the DME is also not coherent because it leads to a complex, overlapping set of charges*";

c. CEG challenged the EA's application of the DME on the basis of its outcome: "*because the deeper connection charge is characterised as a 'market-like' charge (wrongly, in our view – see section 4.1) it is applied before the AoB charge, which is classified as a 'beneficiaries-pay' charge"*;

d. Compass Lexecon considered the DME conceptually reasonable but warned that "*its successful implementation requires that charges be well designed and both exacerbators and beneficiaries be accurately identified*";

e. PwC were concerned about the DME, saying they were "*unconvinced that [it] is a useful means of comparing options or deciding which approaches are preferred. Just because a charge is higher up the hierarchy in the DME framework does not necessarily mean it will score more highly on a cost-benefit analysis than other options*"; and

f. NZIER were concerned about the application of the DME, saying that the EA had "*not provided justification for mechanisms to be classed as market based when they initially appear more administrative".*

3.1.2 Second Issues Paper

119. The topic next appeared in the second issues paper, where the EA presented a lengthy (23 page) elaboration of the DME. I agree with NERA's view that this chapter is "*not contentious from an economics perspective*" and with NERA's conclusion that in its elaboration "*the Authority has identified appropriate economic principles to guide the development of the proposed TPM".* However, I note that none of these additional economic principles form part of any revised DME. Rather, the EA presents them as examples that show how the DME might lead to desirable outcomes.

120. Despite being based on the same DME, very different TPM recommendations emerged as favoured in the EA's first and second issues papers. This was noted by NZIER, who have supported the DME: "*the application of the same set of 'decision-making and economic framework' in TPM1 and TPM2 principles has led to a markedly different allocation of costs between EDBs and direct connect industrials*".

121. Creative Energy noted that the EA's second proposal was primarily based on a beneficiaries-pay approach (the AoB charge) but includes an optional LRMC charge. An LRMC charge is an exacerbator-pays charge, which should be used in preference to a beneficiaries-pay charge according to the DME hierarchy. This led Creative Energy to say "*the DME framework has been turned on its head, with beneficiary-pays now given priority*".

3.1.3 Summary

122. My review of the expert reports identified one report that endorsed this proposition (NZIER) while five criticised the DME itself and another four criticised its application. In addition, Bushnell and Wolak argue that it is *"impossible to use a market mechanism to*

determine cost-effective transmission network investments and set efficient prices for use of the transmission network".

3.2 Evidence of Problem

123. The proposition evaluated in this section is that

There is compelling evidence that one or more problems exist.

124. In its first issues paper, the EA identified several problems with the existing TPM. Noting that "*transmission customers are broadly comfortable with the status quo arrangements for the connection service*", the EA found two "*loopholes*" concerning the boundaries between connection and interconnection assets, which it said could lead to cost-shifting and consequently inefficient decisions.

125. The treatment of HVDC costs was said by the EA to cause three problems:

a. Dynamic inefficiency arising from the fact that beneficiaries-pay charges are not used[17], leading to inefficiently low levels of generation investment in the South Island and "*consumers in both the North and South Islands having an incentive to lobby for future HVDC link upgrades, even if an upgrade is uneconomic*";

b. Inefficiently low levels of generation investment in the South Island (this is part of the previous problem); and

c. Inefficiently low production by South Island generators motivated by avoidance of HVDC costs, which depend on peak output.

126. Interconnection charges were said by the EA to cause four problems:

a. Dynamic inefficiency relative to a beneficiaries-pay structure, causing "*on-going debate and lobbying*" and is "*detrimental to efficient transmission investment decision making*";

b. The RCPD method of setting interconnection charges is causing inefficient investment in demand side response in the lower North Island;

c. Interconnection charges show up in the variable charge component of mass-market power bills, which leads to inefficiently low demand for electricity; and

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[17] I note that the EA characterises the original reasoning for the HVDC charge (first issues paper, ¶4.3.3) as an exacerbators-pay approach (*"reflecting the primary contributors to the costs of the existing HVDC assets"*) whereas Bruce Girdwood (in section 5.2) characterises Transpower's original TPM approach as being based on beneficiaries-pay and says that the current HVDC charge is *"allocated to SI generators as a beneficiary and on the basis that this allocation would have least impact on consumer price (reflected in current TPM Guidelines 15 and 16)"*. I also note that Bushnell and Wolak see the HVDC charge as a beneficiaries-pay charge: *"one of the elements of the current regime that has drawn strong criticism, the charges for the HVDC interconnectors, represents New Zealand's only previous experience with the beneficiaries pay approach"*.

d. Interconnection charges are expected to approximately double over the next few years, which might lead to inefficiently low demand in the upper parts of both islands.

127. The expert reports on the first issues paper were generally silent on the EA's problem definition, in the sense of neither supporting nor challenging it. The exception was Covec, who noted that if the main problem definition (inefficient grid investment due to lobbying, see above at ¶125.a and ¶126.a) is correct then "*it should be possible to identify one or more specific examples of excessive investment, and then to show how lobbying by beneficiaries was instrumental in getting that excessive investment approved and that they benefited from it at the expense of others*". Covec also argued that since grid investment is controlled by the Commerce Commission and based on a cost-benefit analysis, the EA was effectively arguing that its fellow regulator would not be up to the task of resisting self-interested lobbying.

3.2.1 CBA Working Paper

128. In its CBA working paper[18] the EA recorded (at ¶6.2) that submissions on the first issues paper and discussion at a subsequent conference "*indicated that most parties did not agree with the Authority's problem definition and/or the Authority's reasoning as to why the current TPM is inconsistent with economic efficiency*". The EA maintained its view was correct and considered (at ¶6.3) that "*more explanation is required as to why the Authority considers the current TPM is inefficient*". It then provided more explanation.

129. Four expert reports were submitted in response, three of which were explicitly critical of the EA's problem definition, while the fourth (by CEG) did so implicitly in a broader critique of the proposition that changes to the TPM might enhance static or dynamic efficiency.

130. Castalia's view was that the CBA working paper "*does not yet provide sufficient confidence that a credible problem definition will underpin any proposed changes to the TPM*". Castalia also highlighted material differences between the EA's description of, and evidence for, TPM problems arising from the HVDC charge and the interconnection charge, noting that for the latter "*there does not appear to be any clarity on the underlying cause of inefficiency*".

131. NZIER submitted that "*the paper takes the existence of a problem as pretty much a given, a view that is not shared by nearly all of the submitters on the 2012 TPM paper*" and considered that "*a problem with a root cause needs to be categorically identified*".

132. PwC were "*concerned that a clear problem statement in relation to the current TPM still remains elusive*". PwC speculated that EA may "*believe that the current TPM does not appropriately signal efficient investments in transmission and transmission substitutes*" and argued that in that case the problem "*should be explicitly stated in a short problem statement (or series of problem statements) which will act as a guide for developing alternatives to the TPM*".

[18] Electricity Authority, Transmission Pricing Methodology: CBA Working Paper, 3 September 2013.

3.2.2 Problem Definition Working Paper

133. The next discussion of the problems with the current TPM began with the EA's release of its Problem Definition working paper, which was focussed solely on the HVDC and interconnection charges. In respect of those charges, the EA summarised its problem definition in three statements:

a. *the HVDC and interconnection charges fail to promote efficient investment in transmission, generation, distribution, and by load*

b. *the current TPM is not durable, creating uncertainty for investors and therefore inefficient investment*

c. *the HVDC and interconnection charges and PDP fail to promote efficient operation of the electricity industry*.

134. The EA saw a common thread underlying all three problems. It considered (¶8.4 – 8.5) that "*the crux of the problem*" is that "*some customers pay considerably more than the cost of transmission services to them while others pay considerably less*" and this "*over-charging and under-charging results from the fact that transmission costs are effectively socialised across the grid"*.

135. The three problems above were linked by the EA to a larger number of specific problems, the cost of which were estimated to be between \$115m and \$291m in present value (PV) terms, indicating annual costs in the order of \$12m to \$29m.[19]

136. Four expert reports were submitted in response: none were supportive.

137. Castalia gave the EA credit for having sharpened its problem definition, but challenged the nature and scale of the problems claimed. Comparing the EA's estimates of the PV of costs with Transpower's asset base of around \$3bn, and the annual savings of \$267m that consumers could make by switching to the cheapest retailer available in their region, Castalia argued that the EA had identified "a *relatively small problem"*. Castalia also argued that the EA's cost estimates were *"materially overstated because they are derived from multiple sources (not just the TPM)"*. It estimated a range from \$4m to \$101m in PV terms. Castalia focused on the *"most credible"* of the three problems cited by the EA, which concerns the efficient operation of the electricity industry. Regarding the investment problem and the durability problem, Castalia said that there is no evidence that:

a. "*information is withheld from transmission investment decisions*"; or that

b. *"industry engagement [on the TPM] has been detrimental or that changes would remove any disagreements*".

138. More generally, Castalia argued that *"something should only be classified as a problem with the TPM if changes to the TPM could possibly resolve the problem"*. It noted in particular that

[19] It appears that the EA has added the estimated costs for the next 17 years. A fixed annual benefit would accumulate to 10 times its annual value over 17 years at an 8% discount rate, and a factor of ten is evident in this working paper, for example at Table 5.

the EA's role is to produce guidelines for Transpower, not set prices directly, and argued that some of the issues raised by the EA occur during the price setting process, rather than in the guidelines.

139. NZIER was not convinced by the new problem definition work either. NZIER said it was "*concerned with how the Authority is appearing to redefine the problems with the current TPM*" and that "*there appears to be a lack of coherency as to the nature and definition of problems over time and of how they are handled in this new paper*".

140. NZIER also argued that there were "*non-TPM drivers of business decisions made by generators and electricity users*". The point seems to be that conduct that might appear inefficient when viewed through an electricity industry lens might be entirely rational for other reasons and beyond the scope of TPM changes to influence.

141. Like Castalia, NZIER was sceptical about the prospect of a new TPM being more durable: "*We can conceive of these 'problems' equally occurring under other approaches to the TPM".*

142. ASEC did not directly support or challenge the EA's problem definition. However, it took issue with a claim in the working paper to the effect that interconnection services to generators are cross-subsidised by load.

143. PwC considered that the EA had not sufficiently substantiated "*the proposition that prices do not reflect costs*". It also considered that "*many of the issues which are raised are immaterial, over-stated, or able to be resolved through targeted refinements to the current TPM*". The role of the Commerce Commission in approving transmission investments was discussed by PwC who concluded that "*TPM does not have a material bearing on which investments are proposed or approved".*

144. PwC was negative regarding the EA's claim that the existing TPM lacks durability, noting in particular that "*the current TPM is relatively uncontentious when compared to the proposals put forward in the October Issues Paper*". PwC also considered that *"ongoing debate and periodic disputes are likely to be a feature of any TPM"*. Overall, PwC concluded that *"any issues which do exist with the current TPM are of a magnitude which is best resolved through targeted refinements to the existing TPM, similar to that proposed by Transpower under its operational review".*

3.2.3 TPM Options Working Paper

145. The EA also discussed problem definition in its TPM Options working paper.[20] Noting that it was undertaking further analysis of problem definition in preparation for its second issues paper, the EA nevertheless outlined (at ¶1.19 – 1.30) *"a preliminary set of updated views on problems with the current TPM"*. It argued that Transpower's recent large scale investment program had led to *"a nearly 70 percent increase in the strength of the transmission (interconnection and HVDC) pricing signals, encouraging potentially inefficient and unnecessary investment and activity to avoid the charges"*. A divergence of interest between South and North Island customers was indicated, and it was stated that *"postage stamp interconnection charge[s] … result in customers in areas not needing increases in capacity*

[20] Electricity Authority, Transmission Pricing Methodology Review: TPM Options Working Paper, 16 June 2015.

contributing to fund expansions in areas, like Auckland, where capacity is being increased". The EA also noted that North Island generators pay nothing for the HVDC link, though their power flows south through the link when South Island hydro lakes are low. The EA followed these examples by arguing that "*socialisation of transmission charges weakens the incentives of the parties that are recipients or beneficiaries of potential new investment to scrutinise whether the investment is economic or optimal."*

146. Expanding on these views, the EA argues that there are four problems with the existing TPM:

   a. It is not adaptive and sends the wrong price signals;

   b. It does not appear to be cost reflective;

   c. It fails to support the discovery of efficient transmission investment through the transmission investment approval process; and

   d. It may not be durable.

147. Ten expert reports were submitted in response but these were primarily focussed on the TPM options rather than the problem definition. Only three expressed views on the problem definition. One was Castalia, who said "*the problem definition has now progressed to a point that even if stakeholders do not agree that the problems identified exist or are material, stakeholders can now understand what the Authority considers problematic about the current TPM*". CEG and PwC were somewhat less sanguine.

148. CEG agreed that *in principle* (CEG's emphasis) there could be static and dynamic efficiency losses, but argued that "*many of the other problems identified with the current TPM are either mischaracterised or overstated*". In particular, CEG argued that the TPM

   a. "*Has sent efficient price signals in the past*" and *"through Transpower's operational review it is adapting*"; and

   b. "*is cost-reflective from an economic perspective, since all grid users face prices that are greater than the short run marginal cost"*;

149. CEG also argued that there was no evidence that the Commerce Commission's approval process had produced inefficient outcomes, nor was there any reason to expect that the reform options would produce more efficient outcomes in the future. Finally, CEG argued that there is ample scope for incremental reforms in the current guidelines, and that "*the TPM is durable, irrespective of the ongoing controversy, which would persist under any option".*

150. PwC considered that the EA's view of the problem definition had not "*changed significantly since the problem definition working paper was published*". Noting the *"in principle"* merits of cost-reflective pricing, PwC argued that "*a trade-off exists between economically pure approaches, that are difficult to implement in practice or to understand, and administratively simple and fair prices"*. PwC stated that the current "*grid approvals process is robust and decisions are made by an independent regulator that can access and rely on expert*

advice", contested the EA's concerns about durability, and repeated its concerns (discussed above at ¶144) about the relative durability of the new proposed TPM.

3.2.4 Second Issues Paper

151. In its second issues paper, the EA summarised its problem definition (¶6.4) as being that the existing TPM does not promote:

a. Efficient investment in the transmission grid, distribution and generation and efficient investment by electricity consumers; or

b. Efficient operation of the transmission grid, generation, distribution and demand side management.

152. Three specific problems were cited in respect of the HVDC and interconnection charges. These were said to cause:

a. Inefficient use of the HVDC link and interconnected grid;

b. Inefficient participation in investment appraisal processes leading to inefficient grid investment; and

c. A lack of durability which creates uncertainty and leads to lobbying.

153. Most of the expert reports submitted on the second issues paper express no particular view on this problem definition, being instead focussed on assessing the substantive proposals in the second issues paper. Several expert reports summarised the EA's problem definition without explicitly endorsing or challenging it: these were coded as silent on the issue. As noted above (¶127), expert reports responding to the first issues paper were also mostly silent on the problem definition.

154. Two expert reports did comment on the problem definition however: both in opposition.

155. James Bushnell started from the perspective that the nodal pricing (see ¶80 above) system already in place, which is also known as locational marginal pricing (LMP) "*represents the "gold standard" for appropriate marginal pricing incentives*". This system is explicitly designed and operated to provide extremely sharp price signals for electricity usage. Bushnell goes on to say that

> *the desire to add an additional surcharge to LMPs under the guise of long-run marginal cost, or benefits-based charging, is only justified on efficiency grounds if there is a fundamental problem with the LMPs, or the ways network users, and planners, respond to them. If this were the case, the proper response is to address the source of the problem (LMP penalties, the transmission planning process) rather than attempt to correct one distortion by adding another one.*

156. PwC say that the EA "*has identified problems with the current TPM and DGPPs but the proposals for reform create substantial problems themselves*". They "*remain of the view that the concerns regarding durability and scrutiny of transmission investments are over-stated*".

3.2.5 Summary

157. The TPM review process began with the EA defining problem(s) with the existing TPM as including the absence of its preferred solution. This approach does not facilitate a broad search for solutions, and creates a risk that any changes implemented will be less than fully beneficial. While the problem definition was sharpened somewhat as the review progressed, substantial criticisms remained. Over time, arguments against the evolving problem definition focussed more heavily on the EA's description of the interconnection charge problems and the durability problems, and on the EA's estimates of the scale and materiality of problems.

158. My review identified fifteen expert reports that commented on the proposition at issue: fourteen were clearly in disagreement while one was equivocal.

3.3 Robust Identification of Costs and Benefits

159. The proposition assessed in this section is that

> *The EA's cost benefit analysis identifies and assesses the cost, risks and benefits in a robust manner.*

160. The EA presented a cost benefit analysis (CBA) in appendix F of its first issues paper. The claimed benefits of the beneficiaries-pay charging system proposed at that time were said (at ¶3.4) to be:

a. Promoting efficient grid investment;

b. Promoting efficient investment in generation and load;

c. Promoting allocative efficiency;

d. Promoting productive efficiency; and

e. Promoting durability.

161. The categories of cost were identified (¶3.5) as:

a. Implementation costs to set up the new system

b. Operational costs to run the new system

c. Costs to participants of using more complex models to verify their transmission charges; and

d. Incentives on parties to change their use of the grid to avoid charges.

162. In quantifying the benefits, the EA focussed on the *"promoting efficient investment"* items, which are dynamic efficiency issues. Allocative efficiency gains were said to be *"exceedingly small"* and were ignored, as were productive efficiency gains. The EA estimated the dynamic efficiency gains arising from its HVDC and interconnection charge

proposals by taking the total retail electricity revenue in 2011, which was approximately $6.5bn, multiplying it by 0.3%, increasing it annually by 3.8% to reflect industry growth over time, discounting future years by 6.1% per annum and summing benefits over the next thirty years. The resulting estimate was $171.8m in present value (PV) terms.

163. Durability benefits of the new TPM proposal were estimated as the avoided costs of disputes over the TPM, totalling $2.85m per annum. Projecting this cost saving forward for thirty years and discounting led to a PV estimate of $36.5m. The EA also included estimated *net* benefits from its proposed changes to the treatment of reactive support ($13m in PV terms) and connection charges ($2m in PV terms).

164. In total, these benefits were estimated at $223.3m in PV terms over thirty years.

165. On the cost side of the analysis, the EA focussed on the implementation and ongoing cost categories, allowing $50.1m in PV terms. The estimated total net benefits were therefore calculated at $173.2m in PV terms over thirty years.

166. Expert submissions on the first issues paper were very critical of the CBA. None were supportive, three were silent and the remaining eight expert reports were critical.

167. Castalia said that it *"does not systematically assess all elements of the proposed TPM, fails to clearly identify the benefits of any change, excludes the costs of unintended consequences and risks and fails to credibly quantify the benefits of any change."* Castalia also said that *"the CBA … reads as a justification for an option that the Authority already preferred, rather than an analytical tool that helps to select the best way forward"*.

168. CEG noted that the efficiency factor (0.3%), which is the source of most of the benefits in the EA's model, is an assumption rather than an estimate: *"the 0.3% value simply reflects the EA's belief that its proposal will deliver significant economic benefits when, for the reasons we set out… there is good reason to think that it will not"*. CEG also noted that the proposal had the potential *"to amplify risk throughout the entire supply chain, with myriad attendant consequences"*.

169. NZIER were also concerned with the efficiency factor, regarding the EA's dynamic efficiency benefit estimates as a *"quantitative illustration of what the benefits might be if dynamic efficiencies were to occur. It is not a probabilistic assessment of the welfare gains expected to arise, which is what we would have expected to see"*.

170. PwC focussed on omissions from the CBA, saying that it *"over-estimates the net-benefit of moving from the status quo"*, that *"alternative options are only given cursory analysis before being dismissed"*, and that *"although costs arising from maintaining the current TPM are quantified, many benefits from retaining the status are not"*. PWC also considered that the EA should have explained which participants would be *"winners"* and which would be *"losers"* under the proposed re-allocation of transmission costs.

171. NERA, while generally supportive of the EA's proposal, did not consider that the CBA was adequate: *"I consider that the [EA's CBA] does not establish the efficiency improvement between the postage stamp alone and the EA-SPD charge"*. No further comment was provided on the CBA.

172. Redpoint stated that the CBA *"uses highly simplified assumptions that do not provide a robust estimate of improved efficiency resulting from the proposal"*.

173. Reunion cited several weaknesses in the CBA, including the lack of analysis of any other option. The efficiency factor approach to dynamic efficiency benefits was criticised. Reunion also argued that static inefficiencies were omitted, and that the EA had over-estimated the durability benefits and under-estimated the ongoing costs to market participants.

174. Covec challenged three core assumptions underpinning the EA's analysis: that beneficiaries could be clearly identified; that they would then lobby efficiently for grid investment; and that this would defer grid investment. Covec also argued that the EA had omitted three categories of costs: allocative losses arising from using variable charges to recover fixed costs; reduced retail competition; and a higher cost of capital due to higher risks. Covec also criticised the efficiency factor analysis of dynamic efficiency benefits, arguing that even if the general approach was reasonable the effect was overstated both in terms of the 0.3% factor and the revenue base to which it was applied.

3.3.1 CBA Working Paper

175. Cost benefit analysis was the first component of the broader analysis to be the subject of further consultation after the first issues paper. In the CBA working paper, the EA set out a ten-step process for the CBA, and discussed options for addressing these steps. It discussed four general options for assessing effects: international benchmarking; systems modelling, econometric international benchmarking and full-economy modelling using a computable general equilibrium (CGE) model.

176. The EA concluded that a combination of *"top-down"* and *"bottom-up"* modelling approaches was preferred. Potentially, this includes all four of the options considered. The EA also recognised (at ¶1.23) that there was merit in modelling more than one option (as noted by Reunion, see ¶173). Regarding risk and uncertainty (as noted by Castalia (¶167), CEG (¶168 and Covec (¶174)), the EA agreed and stated that it would take *"risk profiles"* into account. The EA also argued (at ¶6.14) that removing or reducing the socialisation of grid costs could be expected to improve static efficiency.

177. Four expert reports were submitted in response. They were generally framed as conceptual analyses, which was consistent with the relatively abstract nature of the working paper.

178. Castalia gave the EA credit for adopting a more disciplined approach to the framework of its CBA but identified two omissions. Castalia said that the working paper *"does not cover important framework issues in deciding on a problem definition and identifying options that would address any problems"*.

179. NZIER were concerned about international benchmarking, stating that *"the use of benchmarking can be problematic if it is assumed that the benchmarks can be transferred to NZ circumstances without a thorough testing process. This approach would leave the door open to on-going dispute about the TPM"*.

180. PwC made several specific suggestions with two being of particular note. PwC suggested that the EA should not focus solely on final prices, but instead break down its analysis to reveal the parts of the value chain (e.g. generation, transmission, distribution, retail) in which impacts were expected. PwC also suggested a re-ordering of the EA's proposed ten-step process, on the grounds that *"sensitivity analysis needs to be conducted prior to the application of any decision making criteria"*.

181. CEG took issue with the EA's view that unwinding the socialisation of grid costs would improve static efficiency. Noting that under the existing TPM the combination of nodal pricing and two-part tariffs is *"likely to result in very efficient usage of the existing transmission assets"*, CEG argued that *"there are unlikely to be any significant static efficiency benefits to be obtained through changing the way that transmission charges are levied for existing assets"*. On the contrary, CEG argue that the beneficiaries-pay proposal creates a risk of static efficiency losses arising from *"reduced wholesale dispatch efficiency, amplified risk throughout the supply chain and, potentially, reduced retail competition"*.

3.3.2 Second Issues Paper

182. In the second issues paper, the EA relied on a consultancy, Oakley Greenwood (OGW), to undertake the cost-benefit analysis. OGW used the status quo as the counterfactual (base case), and assessed two reform options against this counterfactual: the EA's main proposal for an area of benefit (AoB) charge inclusive of other changes; and a new "deeper connection" proposal, under which the boundary between connection assets and the core grid would be shrunk back towards the core grid, reducing the relative importance of interconnection charges in the total cost of transmission faced by any grid customer.

183. OGW used a twenty-year horizon for modelling the costs and benefits of the EA's proposal, except in the case of the HVDC charge, where a thirty year horizon was used. OGW said (at footnote 68) that it changed the modelling horizon for the HVDC charge because *"the 20-year timeframe was unduly influenced by specific timing related issues that affected when generation assets were expected to be developed in the model, which skewed the results when undertaken over this shorter evaluation period"*. In an expert response, Houston Kemp included this change among its list of the *"most significant"* problems with the OGW cost-benefit analysis: *"the selection of a 30 year timeframe for assessing the benefit of removing the HVDC charge, when all other benefits are estimated over 20 years, and not changing this timeframe in sensitivity analysis that purports to show benefits calculated over 10 years, 20 years and 30 years"*

184. OGW assumed a discount rate of 8% per annum, and found substantial gains for both alternatives compared to the status quo. The EA's preferred option came out slightly ahead of the deeper connection option, with an NPV of $213m as against $208m. Explaining this result, OGW said it *"arose from our assumption the AoB charge will have a significantly greater coverage than the deeper-connection charge with regards to future investment and is also likely to avoid more dispute-related costs than the deeper connection-based charge"*. The components of these results are tabulated below.

	Area of Benefit	Deeper Connection
Future investment in services that may be substitutes for transmissions services		
Alternatives to transmission investment	1,202,796	601,398
Deferrals of transmission investment	3,010,839	-
More efficient co-investment in generation and transmission services	92,748,124	92,748,124
More efficient quantities of services being demanded	313,601	143,389
Benefit from more efficient pricing of historical investments		
Removing the HVDC injection charge based on MWh	13,731,094	13,731,094
Replacement of the RCPD charge with a charge based on physical capacity	89,974,887	89,974,887
Introducing a more comprehensive PDP	10,302,309	10,302,309
Net incremental and avoided costs	2,040,441	405,062
TOTAL NET BENEFIT	**213,324,091**	**207,906,263**

185. In the above table I have shaded the items for which OGW estimated that the two options (AoB and deeper connection) would have the same net benefit. These items represent 97% of the net benefits for the AoB option, and 99% of the benefits for the deeper connection option.

186. Of the fifteen expert reports submitted in response to the second issues paper, eight were silent on the proposition that the EA's cost benefit analysis identifies and assesses the costs, risks and benefits in a robust manner, one supported this proposition and six were opposed to it. The comments within the seven expert reports commenting directly on the CBA were of two general types:

a. Comments on the plausibility of the effects modelled; and

b. Comments on the method of estimation.

187. Writing in support of the EA's proposal, NERA endorsed both the plausibility of the effects modelled and the methods of estimation. NERA said that the CBA had *"quantified the most important benefits and costs of the proposal, and is likely to be conservative"*. NERA was not concerned that the AoB charge might not be particularly accurate, arguing that "*it is not necessary to aim for a high level of precision in identifying beneficiaries and benefits in order to achieve material efficiency gains over the status quo TPM".*

188. PwC argued that $93m of the estimated benefits relied on an incorrect assumption that the AoB charge would be equivalent to a *"regional LRMC charge"*. However, the AoB charge is "*calculated at a nodal level rather than a regional level"* and "*the AoB charge is not an LRMC charge*" as the EA has acknowledged by *"adding an LRMC charge as a potential additional component for Transpower to consider"*. PwC also challenged the plausibility of a second large benefit (around $90m PV) estimated to stem from removing the RCPD method of allocating interconnection charges. PwC says that this benefit relies on an assumption that very costly diesel distributed generation will be displaced, whereas solar is the preferred distributed generation technology and is not affected by the RCPD signal because *"it does not generally operate at times coincident with regional peaks"*. PwC were

critical of the smaller benefits attributed to removal of the HVDC charge, expanded prudent discount policy and deferred transmission investment. PwC also said that the estimated benefit from reduced dispute costs was *"simply implausible and reveals a real lack of comprehension of the nature of the proposal being put forward and how participants will respond to it"*.

189. Castalia, while acknowledging that the EA was responding constructively to feedback, was very critical of the CBA. Castalia argued that *"a wider range of costs and benefits could be taken into account"* including costs to participants of working within the proposed new TPM. Castalia's second point was that *"specific modelling assumptions may lead to an overstatement of benefits"*, specifically: due to the presence of intermediaries (lines companies and retailers) it is not correct to assume that *"changes to the TPM perfectly flow through to end users as cost-reflective retail prices"*; and that it is inappropriate to assume that *"diesel facilities are used to avoid peaks at present"*. Finally, and consistent with its view that more work is required, Castalia considered that *"subsequent CBAs should focus on the marginal impacts attributable to the decision being proposed and use sensitivity analysis to examine uncertainties"*.

190. NZIER say that *"the CBA analysis does not provide compelling evidence that the best option has been chosen"*. Noting that the value of net benefits is small compared with transmission costs, NZIER point to specific concerns over the two largest items:

a. The $90m benefit from replacing the RCPD charge with an AoB charge *"relies on a substantial increase in diesel generation – if this is replaced with reliance on demand response the net present value of the removal of the RCPD is negative"*;

b. The $93m benefit from more efficient investment in generation *"relies on Oakley Greenwood re-ordering the implementation sequence of two sets of new generation plants that are almost the same"*.

191. Axiom says that *"the CBA rests on three foundational assumptions that do not hold"*. These assumptions are described and critiqued by Axiom as follows:

a. The CBA assumes that the AoB charge would provide an efficient *ex-ante* price signal, but Axiom argue it would be an *"inefficient price signal that risks compromising static and dynamic efficiency"*;

b. The CBA assumes that the proposed reallocation of costs would not cause inefficient reductions in demand, but Axiom argue that there would be "*a significant allocative efficiency loss*" even if only a small proportion of extra charges to load were "*passed through as volumetric charges*";

c. The CBA assumes that the AoB (and deeper connection) charges can be proxied by the LRMC of transmission in each of the four parts of New Zealand used for the RCPD charging system, but this *"will only true on average but, importantly, wrong in each individual case, which undermines a great deal of the modelling"*.

192. Scientia focussed on the modelling required to implement the proposed AoB charge. Scientia noted that in its second issues paper the EA did not demonstrate or test the full effect of the AoB charge.

193. Houston Kemp were very critical of the CBA, saying it *"does not enable us (or, anyone) to form a conclusion as to whether the EA's proposal is likely to give rise to net benefits"*. In particular, Houston Kemp said that the CBA does not evaluate the EA's proposal, but instead *"more closely resembles an assessment of the benefits of an LRMC charge"*, a point also made by PwC (¶188) and Axiom (¶191). Houston Kemp challenged both the assumptions and methods used in the CBA. Key points include:

   a. The assumption that the existing TPM will induce 500MW of new diesel generation is said to be *"out of all proportion to the current scale of diesel generation"* and in *"direct contrast to the conclusions that the EA itself drew in relation to changes to the existing TPM implemented this year"*;

   b. The modelling of efficient generation *"contains substantial implementation errors and cannot be relied upon"* (a similar point was made by NZIER at ¶190);

   c. Use of a *"30 year timeframe for assessing the benefit of removing the HVDC charge, when all other benefits are estimated over 20 years"*, an approach that could have been mitigated in sensitivity analysis but was not; and

   d. The *"exclusion of deadweight losses in assessing the costs and benefits of higher prices leading to a decrease in quantity demanded"* (a similar point was made by Axiom at ¶191).

194. Houston Kemp also said that the CBA is sensitive to assumptions about whether the Huntly power station remains in service or not, and that OGW has used different assumptions *"depending upon the category of benefits that it assesses"*.

3.3.3 Summary

195. In my opinion, the expert evidence suggests that the proposition at issue is false: neither of the cost benefit analyses has assessed the costs, risks and benefits of the EA's proposed replacement TPM Guidelines in a robust manner.

196. I acknowledge that it can be very difficult to robustly quantify the costs, risks and benefits of proposed changes to a TPM, particularly when those proposals are major, as they are here, rather than incremental. Faced with such difficulties, analysts have a broad choice between what might be thought of as black-and-white and full-colour approaches. The former leads to simplification and a focus on the big issues, while the latter places emphasis on matters that may seem second-order if one endorses the general thrust of the proposal.

197. It seems to me that the CBAs published with the first and second issues papers both lean towards the black-and-white. Analysts conducting both CBAs have at least implicitly assumed that the proposals will have desirable effects on conduct: that investment will be more efficient, that disputes will reduce and that there will be no static inefficiencies. The

investment efficiency aspects of the resulting CBAs have, at best, weak causal connections to the specific proposals and the market conduct that might follow if they were implemented. Thus, in the first CBA, analysts estimated dynamic efficiency effects using a method that could never have delivered a negative result and for which the upside was capped by the extent of their optimism. On the second set of proposals, analysts modelled regional LRMC charges instead of the proposed nodal AoB charges.

198. A second identifiable source of optimism bias is in the EA's consistent denial of static efficiency losses arising from the fact that increases in power bills (e.g. in northern parts of the country) will lead to lower consumption of electricity, and hence less usage of the grid. Even NERA, the only expert to have consistently supported the EA through this process, warned the EA in its response to the first issues paper (at s3.1) that the beneficiaries-pay approach *"reduces static efficiency"*.

199. These approaches to modelling static and dynamic efficiencies would only be acceptable if the intended audience for the CBAs had already agreed to support the proposals, and were looking for a broad indication of the overall benefits. It is therefore to be expected that experts who are unconvinced that the proposals are beneficial, which is the vast majority of the experts, are unconvinced that the CBAs assessed the costs, risks and benefits of the EA proposals in a robust manner.

3.4 Established that an AoB Charge Will Send Desired Price Signals

200. The proposition assessed in this section is that

> *The EA has established that an AOB charge will send desired price signals.*

201. This is an important proposition because the EA has consistently argued that the lack of efficient price signals is a fundamental problem with the TPM. This view is apparent from the EA's statements about the socialisation of grid costs, as cited in the quotes from the EA at ¶134 and ¶145 above, for example.

202. In its first issues paper, the EA's executive summary started by noting that, in markets, prices reflect the costs of supply and that, when many costs are shared, the prices paid by individuals are *"often linked to the private benefits"*. Referring to the existing TPM, the EA then said that the *"HVDC and interconnection charges are not efficient as the charges do not necessarily relate to the costs and benefits"* of the services received from each grid asset and that these charges are also *"inflexible and not durable"*. It was then stated that *"the party that benefits should pay"*, following which attention moved swiftly to methods for achieving this outcome.

203. This approach assumed that a highly granular beneficiaries-pay charge would be an improvement on the status quo, *before* considering the practical issues associated with implementing such a charge. This created a risk that the method chosen for implementing beneficiaries-pay charges on a per-asset basis might be so costly as to outweigh any benefits. All of the expert reports that were critical of the first proposal made reference to aspects of the implementation method proposed, and as noted above (¶198), even NERA noted implicitly that static efficiency costs had been omitted from consideration.

204. The second issues paper was presented differently and the lacuna noted above (¶203) was not explicit. The beneficiaries-pay charge had been renamed as an AoB charge (notwithstanding that the area concerned related to individual nodes) and the implementation of this charge had been simplified somewhat. Nevertheless, as noted by PwC (¶188), Axiom (¶191.c) and Houston Kemp (¶193), the proposed AoB charge was not modelled in the CBA. We can therefore not conclude, despite the positive CBA, that the EA has established that *its proposed* AoB charge will send desired price signals.

205. There was also a serious expert challenge to the practicality of the proposed guidelines. Scientia argued that the results would be very sensitive to modelling assumptions. Noting that *"the AoB approach described in the Authority's consultation paper indicates the estimation of benefits over the life of the asset whereas the modelled approach was for a single modelled future year (2019)"*, Scientia shifted the year of assessment from 2016 to 2015 but otherwise followed the EA's modelling approach. One result of this change was *"a significant reduction in the assessed benefit calculated at the largest upper North Island (UNI) beneficiary in the week in which it received its largest net benefit ($4.4m to $0.1m - a 97% reduction)"*. Scientia considered that such a large change in benefit estimate from a small change in input assumptions was problematic.

> *We consider that such extreme variations in the assessed benefits at nodes could be expected to occur if Transpower used the modelled AoB approach as assumptions about the entry and exit of generators and loads, their offers and bids, transmission network and security constraints over a twenty year modelling horizon could significantly affect the calculated nodal prices, cleared nodal generation and load and consequentially the calculated benefits and cost allocation of each node. We consider this volatility would reduce Transpower's ability to justify the credibility of the calculated nodal benefits (and cost allocation) as the modelled AoB approach based on these nodal benefits is intrinsically dependent on the choice of modelling assumptions.*

206. Scientia also emphasised the difficulty of the task, saying that the proposed guidelines "*would require Transpower create a forecast of nodal prices, cleared generation and load quantities several decades into the future and use these forecasts as the basis for estimating private benefits*". Scientia was also concerned with an assumption underlying the CBA that *"transmission, generation and load investment and retirement decisions are independent of one another"*. This assumption is implicit in the CBA because the benefit of each grid customer is assessed with and without particular grid assets, without any other change in the design or use of the system.

207. Nevertheless, there was some support among the experts that, *in principle*, an AoB charge could send desired price signals. Focussing on responses to the second issues paper, we noted the following support for that proposition.

a. EPOC *"supports the general principle of beneficiary pays for electricity transmission"*.

b. PwC suggested that if the EA were to restrict *"the AoB charge to new assets only…this would still send the price signal the Authority is seeking"*.

c. Castalia, while arguing for *"enhancements to the proposed AOB charge"* also said that *"the AOB charge is able to meet the Authority's objectives and we support this aspect of the proposal"*.

d. NERA says that *"the basic premise of the … AoB proposal is that grid costs should be allocated to beneficiaries … according to their share of the benefit. This is an appropriate principle"*.

e. Compass Lexecon, while critical of the EA's proposal, states that *"a charge based on the beneficiaries-pay principle to pay only for new investments"* would be part of its preferred, non-distortionary TPM.

208. These views were far from universal however, with clear opposition to the principle of beneficiaries pay from the following experts in response to the second issues paper.

a. James Bushnell noted that *"measurement of these values requires either complicated modeling, which can be influenced by disputable and opaque assumptions, the risk of distorting ongoing network usage in an effort avoid being labeled a beneficiary, or both"*. See also ¶214.a below for further comments on this point from Professor Bushnell.

b. Axiom summarised its opposition as follows. *"…the AoB would not achieve either of these objectives as it is currently framed in the draft Guideline. The charge could not elicit desirable behavioural change because the implicit 'shadow price' signal would be inefficient. And the extent to which it could give rise to a less distortionary allocation of sunk costs would depend upon many factors, including the way in which private benefits were estimated."*

c. Creative Energy Consulting compared the EA's approach with Ramsey pricing and found it severely wanting. *"Ramsey pricing does not entirely avoid the distortions and inefficiencies associated with backward-looking prices, but it does minimize them. In trying to do better than this, in striving for the ultimate ideal of zero distortions, the EA has concocted a chaotic mixture of retrospective prices, ad hoc resets, mysterious formulae (for new customers) and new bypass incentives. This concoction will not be durable or effective. It will be a shambles."*

209. More generally, I consider that little weight should be attached to statements of *in principle* support for beneficiaries pay concepts because so much depends on the details. For example, it is clear that the beneficiaries of the grid are already paying for it. The EA's consistent preference since 2012 for highly granular charges, in which the cost of each asset in the interconnected grid is separately allocated to specific grid customers, has attracted widespread expert opposition.

3.5 AoB Charge is Superior to Alternatives

210. The proposition assessed in this section is that

> *The area-of-benefit (AoB) charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and tilted postage stamp.*

211. In assessing this proposition, I treat the beneficiaries-pay charge proposed in the first issues paper as an AoB charge. While some expert reports have expressed overall conclusions about whether the proposed changes are superior, most of these concluding statements are relative to the status quo rather than to one, let alone all, of the alternatives cited in the proposition above. For completeness, I will document all of the overall views that are explicit or implicit in the expert reports, irrespective of whether they are relative to the status quo or include reference to alternatives.

3.5.1 First Issues Paper

212. Eleven of the expert reports submitted on the first issues paper were reviewed. Of these, nine disagreed with the proposition, one agreed and one, though critical of the proposal, did not express an overall view. This weight of negative expert reviews may have been instrumental in the EA focussing on sub-components of the overall TPM development problem for the subsequent several years. Summary comments from the expert reports are presented below.

a. Castalia did not agree that the proposal would be an improvement, saying "*the proposal needs to be redesigned in order to achieve the outcomes sought by the Authority*".

b. CEG identified several concerns with the proposal and its evaluation and concluded that the methodology "*may in fact not offer any net efficiency benefits and may instead impose a net cost on the market, if it is introduced*".

c. NZIER identified several concerns with the proposal and its evaluation and concluded 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*".

d. PwC raised numerous substantive concerns but did not express an overall view.

e. Marsden Jacobs identified several concerns with the proposal and its evaluation and concluded that "*the complexity and increased risk associated with the SPD methodology was not supportive of economic efficiency and was not supportive of lower costs to customers*".

f. NERA was asked whether the proposal was superior to the status quo and concluded that "*on the basis of economic principles and empirical findings relating to the EA's methodology the answer is yes*".

g. Redpoint, referring to the highest-level objective of outcomes that result in long-term benefits for electricity consumers say that "*it is unlikely that the EA would meet this objective through implementing the proposed TPM*".

h. Reunion concluded that *"the Authority's analysis to date is not robust enough to support the proposed TPM"*.

i. Frontier stated that *"given the indirect link between network users' decisions and transmission investment decisions, there is nothing intrinsic to a beneficiary pays approach as applied to existing transmission assets that ensures economically efficient outcomes"*.

j. Covec concluded that *"the EA should reconsider the specific problem(s) it is seeking to address and explore alternative ways to: improve grid investment processes to make them less vulnerable to lobbying; signal the costs and benefits of location choices to generation and load; and directly address weaknesses in the current HVDC cost allocation"*.

k. EPOC cited seven reasons for this summary statement: *"EPOC does not support the proposed transmission charging regime as it is described in the supporting documents"*.

3.5.2 Beneficiaries-Pay Options Working Paper

213. In its Beneficiaries-pay Options Working Paper, the EA described three main options that differ according to: the method used to identify beneficiaries and estimate benefits; and the assets to which they would apply. All methods used the SPD model but they did so in different ways. The three main options were:

a. Simplified SPD, applying to investments including replacement investments added to Transpower's asset base between 28 May 2004 but before 10 October 2012 and worth at least $50m, and subsequent investments worth at least $20m;

b. GIT plus SPD, applying to the same assets as for "simplified SPD"; and

c. Zonal SPD, applying to all assets irrespective of their installation date.

214. None of the expert submissions in response could be interpreted as supporting the proposition. Their main points are discussed below.

a. James Bushnell, in a very thoughtful paper, argues that *"beneficiaries pay, while a perfectly reasonable principle for framing the fairness of allocating costs, offers little real benefit in terms of the efficiency of investment incentives in markets with sophisticated congestion pricing of transmission"*. Bushnell also suggests that, unless the funding of *new* investments is manifestly inequitable, *"it is difficult to envision cases where an allocation of capital costs linked to precisely calibrated estimates of benefits can significantly improve efficiency"*. I agree with Professor Bushnell on these points and consider two facts to be relevant to them. First, there is no evidence of inefficient grid investment, so the EA is responding to a perceived risk at most. Second, there is a completely un-explored middle ground between the existing TPM and the *"precisely calibrated estimates of benefits"* promoted by the EA since 2012.

b. Castalia focussed on specific design issues. Castalia argued that the EA's options were too narrowly drawn, suggested that the EA may have failed to *"obtain value from consulting on the working paper"*, and recommended that the EA re-start its consultation on beneficiaries pay option in a new working paper *"that does evaluate a broader range of options against their ability to improve efficiency"*.

c. CEG also focussed on specific design issues, concluding that *"principal sources of allocative and dynamic benefits cited by the EA are unlikely to transpire"*. CEG also argued that *"if implemented, the options have the potential to give rise to significant inefficiency costs"*.

d. NZIER was unconvinced of the proposition, saying that regardless of the beneficiaries-pay option chosen, *"there remains a list of formidable matters outstanding e.g.: quantitative CBA of the full TPM package; minimising pass through of charges (especially residual charges) from generators to consumers to improve dynamic efficiency gains from TPM; ensuring the TPM is integrated into the wider regulatory system; and ensuring charges do not inefficiently penalise decisions by load and generation not to rely on interconnection"*.

e. PwC did not endorse the proposition. PwC were concerned at the narrow scope of the options presented and "*surprised that no non- SPD alternatives are considered in detail, particularly given 38 out of 45 submitters opposed the original SPD proposal"*. PwC also argued that more thought should be given to exacerbators-pay charges, particularly LRMC charges.

3.5.3 TPM Options Working Paper

215. In its TPM Options working paper the EA proposed three options structured as follows.

a. Base option, containing the existing connection charge and a new "deeper connection" charge – both charges being offset by the loss and constraint excess (LCE) – an AoB charge modelled on the GIT + SPD option from the Beneficiaries-pay Options Working Paper (see above at ¶213.b) but including a broader range of investments, a kvar charge to cover the cost of reactive support, and a flat-rate (postage stamp) residual charge;

b. Base option + LRMC charge, containing the entire base option plus an extra LRMC charge that would only apply before contemplated investments were undertaken, with the investment costs reverting to being part of the AoB charge post-investment; and

c. Base option + SPD charge, containing the entire base option plus an SPD charge "*to recover the revenue for large recent and future transmission investments beyond the boundary of the deeper connection charge"*.

216. Ten expert reports were submitted on the TPM Options working paper. As detailed below, eight of these reports either explicitly or implicitly disagreed with the proposition that the area-of-benefit (AoB) charge is superior to the alternatives. The other two expert reports were silent on this point.

a. James Bushnell acknowledged that there is "*likely some merit*" in the EA's rationales for an AoB charge (i.e. greater scrutiny of grid investment by market participants and greater incentive to reveal their own investment plans) but cautioned that each of these effects could also turn negative. More generally, Bushnell continued to argue that the entire direction of AoB charging is misplaced given the sophisticated system of LMP already in place in New Zealand (see above at ¶80). The following passage summarises Bushnell's view on this high-level issue: *"…the desire to add an additional surcharge to LMPs under the guise of long-run marginal cost, or benefits-based charging, is only justified on efficiency grounds if there is a fundamental problem with the LMPs, or the ways network users, and planners, respond to them. If this were the case, the proper response is to address the source of the problem (LMP penalties, the transmission planning process) rather than attempt to correct one distortion by adding another one"*.

b. Compass Lexecon argued that there is a significant economic difference in the efficient pricing of existing and yet-to-exist assets. For existing assets, the capital investment has been committed and *"the best TPM is one…which users of the system, whether loads or generators, cannot avoid"*. This requires a *"wide base"* (i.e. all grid users contributed) with a relatively low common (postage stamp) charge that is *"independent of location and actual consumption"*. Compass Lexecon further argued that *"the beneficiaries-pay principle…should be used <u>only</u> to finance new investments as a way to promote dynamic efficiency, by making beneficiaries accountable for the expansion of the grid"* (<u>emphasis</u> added). I conclude that Compass Lexecon would not have supported the proposition as it applies to the options proposed in the TPM Options working paper.

c. Castalia did not address the in-principle question, but would not have endorsed the proposition on the basis of the AoB charging proposed in the TPM options working paper. This can be safely inferred from their stated concerns, particularly that *"the options presented in the working paper are unnecessarily narrow"* and that further consideration should be given to three other options that Castalia labelled *"defining broader asset pools, charges for individual assets, and enhanced status quo"*.

d. CEG did not address the in-principle question, but would not have endorsed the proposition on the basis of the AoB charging proposed in the TPM options working paper. This can be safely inferred from their stated concerns, particularly that *"the AoB charge may give rise to significant inefficiencies if it is implemented as currently designed. Most notably levying charges on all generators based on MWh in the manner proposed in the Options Paper has the potential to distort wholesale market outcomes and lead to higher prices"*.

e. Creative Energy Consulting presented an analysis of transmission pricing from first principles. Pricing objectives were grouped into primary, secondary and tertiary categories. The primary pricing objectives were said to be revenue adequacy, long-run efficiency and short-run efficiency. Secondary objectives were said to be transparency, stability and durability. Tertiary objectives were said to include equity and transmission planning efficiency. Creative Energy Consulting concluded that *"pricing methods based on beneficiary-pays are likely to detract from the primary and secondary pricing objectives"*.

f. EPOC did not address the in-principle question, but would not have endorsed the proposition on the basis of the AoB charging proposed in the TPM options working paper. This can be safely inferred from their stated concerns over the AoB charge, albeit that this was limited to its allocation. EPOC said that the *"AoB charge [should] be allocated on a HAMI basis, since a per MWh charge can be distortionary during low-price periods"*.

g. PwC did not address the in-principle question, but would not have endorsed the proposition on the basis of the AoB charging proposed in the TPM options working paper. This can be safely inferred from their stated concerns, particularly that *"the perverse incentives and distortions created by the proposed TPM may outweigh any distortions created by the current TPM, particularly once the changes made as a result of Transpower's operational review come into effect"*.

h. NZIER did not address the in-principle question, but would not have endorsed the proposition on the basis of the AoB charging proposed in the TPM options working paper. This can be safely inferred from their stated concerns, particularly in the following passage. *"We see the AoB charge as static rather than dynamic. The combination of the long review period for the deeper connection charges and the static nature of the AoB allocation suggest that once they are established both of these charges are unlikely to be responsive to shorter term changes in grid costs or use of the grid"*.

3.5.4 Second Issues Paper

217. As outlined above (¶92 – 97), in its second issues paper the EA proposed an area of benefit (AoB) charge as part of a broader package of changes. The cost-benefit analysis (CBA) of this AoB-based proposal found it to be slightly (approximately 3%) better than an alternative "deeper connection" proposal. The CBA attracted considerable criticism as discussed above (sections 3.3.2 and 3.3.3). In this section I review expert submissions on the second issues paper, as they relate to the proposition that AoB charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and tilted postage stamp.

218. Eleven expert reports submitted in response to the second issues paper expressed views that bear on the proposition at issue. All but Stephen Littlechild expressed reservations about the EA's proposals, but it is notable that Littlechild did not explicitly endorse the EA's proposals. Four experts agreed with the *idea* of a beneficiaries-pay charge (EPOC, Castalia, NERA and Compass Lexecon) but each of those also requested changes to the proposed form of the AoB charge.

219. EPOC did not directly address the proposition, but did say that it *"supports the general principle of beneficiary pays for electricity transmission"*. EPOC expressed concern over an aspect of the AoB charge, namely the proposal that asset values be optimised in certain situations.

220. PwC presented two options that it considered superior to the AoB proposal. PwC's preferred option was the status quo and its second-best option was to "*change the AoB charge to new assets only (ie assets commissioned after the date the TPM Guidelines are published), thus avoiding the retrospective reallocation of sunk costs*". These preferences show that PwC would not have supported the proposition.

221. Castalia expressed in-principle support for AoB charges, saying: "*the AOB charge is able to meet the Authority's objectives and we support this aspect of the proposal*". Castalia went on to suggest specific enhancements concerning: *"the thresholds for the different approaches, circumstances for adjustments, [and] the asset valuation approach used"*. On the threshold point, Castalia suggested alignment with Commerce Commission regulation, noting that *"the threshold for consultation on a major capex project or base capex programme has been set at $20 million in the capex input methodology. This followed consultation with stakeholders over the merits of consultation at various levels when determining the IMs. Without an avenue to utilise information on smaller investments, there appears little potential for efficiencies but legitimate administration costs from applying an AOB charge to investments under $20 million"*.

222. NZIER disagreed with the proposition, saying that *"the CBA analysis does not provide compelling evidence that the best option has been chosen"*. NZIER cited several specific concerns, notably that *"the value of the net benefits is small in comparison to both the transmission costs and the cost and benefit streams modelled suggesting that the positive result is sensitive to the assumptions*" and that *"the net present value of the deeper connection option is similar to the net present value of the AoB option suggesting it is a credible alternative even with its increased complexity"*.

223. Stephen Littlechild did not directly address the proposition, but was of the view that the proposals in the second issues paper were an improvement on the status quo. He said in particular that the proposals would *"move in the direction of prices that are more closely reflective of costs and benefits than the present TPM"*.

224. NERA did not directly address the proposition and was critical of some parts of the proposal, notably the ability for Transpower to modify its AoB regime in response to a material change in circumstances, the asset valuation proposals and the methods for actually allocating AoB costs to generation and load. NERA did express in-principle support for the concept of AoB charging, however, saying it *"is an appropriate principle (and in accord with workably competitive market outcomes)"*.

225. Axiom discussed the principles of transmission pricing and expressed the view that the EA's proposals had improved on earlier iterations. Axiom explicitly disagreed with the proposition as it relates to the status quo, however, saying: *"a number of issues would still need to be addressed before the proposal could potentially improve upon the status quo*".

226. Scientia did not directly address the question of whether the AoB charge is superior to alternatives, but did raise concerns over the practicality and credibility of the AoB approach. Scientia said: *"we consider that very significant design and implementation issues exist with the modelled AoB approach which we believe affects its ability to be used as a practicable, stable and credible process for Transpower to allocate transmission costs to its customers".*

227. Creative Energy Consulting discussed the principles of transmission pricing, identified several problems arising from the EA's proposals, and said that these could have been avoided if the EA *"had followed the conventional approach to minimizing the distortions created by backward-looking "taxes": Ramsey pricing"* which *"may well lead to a price structure similar"* to the status quo. The following quote shows that Creative Energy Consulting disagreed with the proposition: *"In trying to do better than this [Ramsey Pricing], in striving for the ultimate ideal of zero distortions, the EA has concocted a chaotic mixture of retrospective prices, ad*

hoc resets, mysterious formulae (for new customers) and new bypass incentives. This concoction will not be durable or effective. It will be a shambles." In a follow-up paper, Creative Energy Consulting supplied a convincing rebuttal of NERA's view that *"grid costs should be allocated to beneficiaries… according to their share of the benefit. This is an appropriate principle (and in accord with workably competitive market outcomes)"* and stated that while regulating electricity transmission in the UK, "*Littlechild never proposed or supported BP-based approaches to transmission pricing or transmission prices – or in any other context – in this role. During this period, LRMC-based transmission pricing was introduced*".

228. Houston Kemp was clearly not convinced that the proposition at issue is valid. Houston Kemp focussed on the CBA and concluded that *"it does not establish that the EA's proposal gives rise to net benefits – and leaves open the prospect that the EA's proposal may give rise to net costs"*.

229. Compass Lexecon characterised the ideal TPM as being one that *"satisfies the minimum distortion principle and provides the right signals for efficient use of the grid and efficient investment"* and argued that a charge for new investments based on the *"beneficiaries-pay principle"* could provide the *"right signals".* Despite this in-principle support for an AoB charge, Compass Lexecon considered that the EA's proposal was unwise, saying that it *"attempts to include sunk costs under different tariff charges, some of them directly related to assets (deeper connection) and benefits (AoB). These charges will be paid by generators and loads. As long as these charges are applied to existing assets, the proposal fails to implement the minimum distortion principle for sunk cost recovery".* I conclude that Compass Lexecon disagreed with the proposition as it applies to the EA's proposal.

3.5.5 Summary

230. The proposition assessed in this section was "*that the area-of-benefit (AoB) charge is superior to the alternatives including the status quo, modified status quo, LRMC charging and the tilted postage stamp*". In reviewing the expert reports that bear on this proposition, I have widened its scope to include a broader range of comment. I have identified and cited thirty-four expert reports (submitted in response to four EA consultation papers) that are informative as to the authors' views on the proposition.

231. Two of the thirty-four expert reports reviewed explicitly stated that an EA proposal was superior to the status quo: NERA's response to the first issues paper in 2012 (see ¶212.f), and Stephen Littlechild's response to the second issues paper in 2016 (see ¶223). I note that on the second issues paper, NERA were among several others (EPOC, Castalia, Compass Lexecon) in offering *in principle* support for an AoB charge, while advocating changes to the EA's proposals for this charge.

4 Expected Outcomes from Preferred Option

232. In this section I evaluate a set of propositions associated with the EA's preferred TPM Guidelines. Since the EA has only issued two complete proposals, I focus on how the expert reports assessed those two proposals. This approach omits reference to the nine consultation documents published between the EA's first and second issues papers, but seems appropriate given the focus in this section on likely outcomes, and the fact that the most of the other consultation documents were reviewed in the context of the framework analysis presented in section 3 above.

4.1 Long Term Benefits for Electricity Consumers

233. The proposition assessed in this section is that

The proposed guidelines are likely to promote long-term benefits for electricity consumers.

4.1.1 First Issues Paper

234. I was able to discern an opinion on this proposition from six of the expert reports submitted in response to the first issues paper: none were supportive of the proposition and many were openly negative.

a. Castalia disagrees with the proposition, saying that their work has been *"completed from the perspective of maximising the long-term benefits to consumers, rather than the interests of any particular market participant or group of participants. We find that the benefits of the proposed TPM through changes in efficiency will not outweigh the estimated costs of implementation and operation"*.

b. CEG disagrees with the proposition, saying that *"the higher wholesale prices that would result from generators adjusting their bids to avoid the incidence of sunk costs and to incorporate additional risk premiums are unambiguously harmful for consumers"*.

c. NZIER did not comment directly, but can be fairly seen as not supporting the proposition. While not opposing the EA's direction of travel, NZIER 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."*

d. Redpoint disagreed with the proposition, saying *"it is unlikely that the EA would meet this objective through implementing the proposed TPM"*.

e. Covec disagreed with the proposition, saying *"there will be some inefficient curtailment of energy use by end-users induced by the fact that fixed transmission costs are passed through in the variable energy tariff, an effect that is difficult to reconcile with the statutory objective of the Authority to advance the long-term benefit of consumers"*.

f. EPOC effectively disagreed with the proposition, saying: *"The apparent elegance and simplicity of this proposal hides some unfortunate features, primarily in the incentives that it provides to alter offer behaviour. EPOC takes the position that these incentives are likely to make the proposal unworkable"*.

4.1.2 Second Issues Paper

235. In response to the second issues paper, I discerned opinion from nine expert reports, eight of which disagreed with the proposition.

a. Castalia can be considered to have disagreed with the proposition, having raised several serious criticisms of the EA's proposal, which can be summarised as follows: "*further improvements to the guidelines are needed to achieve the Authority's objectives for the TPM*".

b. Axiom can be considered to have disagreed with the proposition, having raised several serious criticisms of the EA's proposal, which can be summarised as follows: "*The extent to which the proposal would ultimately represent an improvement upon the status quo depends to a critical extent upon whether some key issues can be addressed*".

c. Scientia can be considered to have disagreed with the proposition, having raised several serious criticisms of the EA's proposal, which can be summarised as follows: *"Based on our assessment, we consider that very significant design and implementation issues exist with the modelled AoB approach which we believe affects its ability to be used as a practicable, stable and credible process for Transpower to allocate transmission costs to its customers".*

d. Creative Energy Consulting disagreed with the proposition. "*Emerging eventually out of this mess, once the quest for fixed charging is abandoned and once all assets are repriced, will be a pricing structure that is not so far away from the Tilted Postage Stamp (TPS) approach that the EA has summarily rejected. TPS prices are not asset based and will not suck customers into the planning process as the EA desires. But they will give customers efficient, transparent, stable prices that they are able to respond to. That, for me, is the critical test of any pricing reform. If it cannot provide such prices, it cannot advance the long-term interests of consumers*".

e. Houston Kemp can be considered to have disagreed with the proposition. Houston Kemp focused on the cost-benefit analysis, which it concluded *"does not provide a robust basis to support the EA's proposal because: its analysis does not, in fact, evaluate the EA's proposal, but instead an assumed efficient price signal that it does not establish would be provided by the proposal in practice; its analysis contains numerous errors in its assumptions and method that call into question its reliability; and; its analysis is not conducted in a fashion that is consistent with best practice for cost benefit analysis, including the EA's own guidelines".*

f. PwC disagreed with the proposition: "*the proposals for reform create substantial problems themselves and it is not clear that the benefits would outweigh the costs*".

g. NZIER appear to disagree with the proposition: *"The CBA analysis does not provide compelling evidence that the best option has been chosen"*.

h. NERA would support the proposition. Section 10 of the NERA report explains why NERA *"broadly agree"* with the EA that the proposed changes will be of long term benefit to electricity consumers.

i. Compass Lexecon can be considered to disagree with the proposition: "*The EA's proposal, however, fails to satisfy fundamental principles for transmission pricing and, therefore, will not promote efficiency*".

4.1.3 Summary

236. The expert reports weigh heavily against the proposition that the EA's proposals are likely to promote long-term benefits for electricity consumers. Only one of the fifteen expert reports commenting on this proposition expressed support. Since this proposition is so closely related to the statutory objective, I have considered the likely effect of the Supplementary Consultation proposal released in December 2016 on the expert opinions discussed above. My assessment is that the concerns expressed by experts on the second issues paper are unlikely to have been eliminated by the measures proposed in the Supplementary Consultation.

4.2 Improved Efficiency of Generation and Load Investment

237. The proposition assessed in this section is that

> *The proposed guidelines are likely to materially improve the efficiency of future investments in generation and load.*

4.2.1 First Issues Paper

238. I was able to discern an opinion on this proposition from four of the expert reports submitted in response to the first issues paper: three clearly disagreed; one offered limited support.

a. Castalia had a negative opinion overall but did offer limited support for this proposition: *"The proposed TPM could have some benefits in moving towards a more optimal combination of transmission, generation, and load investments in the future"*. However, Castalia expressed concern over investment efficiency problems, saying that the method proposed for estimating the beneficiaries-pay charge *"undermines the perceived fairness of the charge to an extent that is likely to impact on the confidence of market participants and major electricity users to invest."*

b. Reunion disagreed that investment efficiency would improve: *"we do not believe the Authority can confidently claim any dynamic efficiency benefits at all"*.

c. Frontier disagreed: "*allocating a proportion of the residual charge to generators could distort generator investment decisions*".

d. Covec disagreed: *"extra risk will be added to generator net revenues, increasing the cost of capital and therefore raising the hurdle for new investment"*.

4.2.2 Second Issues Paper

239. Only five experts stated views that bear on this proposition in response to the second issues paper: all five disagreed.

a. PwC appear to disagree with the proposition. PwC set out (at ¶50) a list of five things that market participants need to understand in order for the claimed efficiency benefits to occur and then argued that *"only very large sophisticated players will have this information and be able to act accordingly"*.

b. Axiom disagreed with this proposition, saying that *"the AoB charge … risks incentivising inefficient consumption and investment decisions by load."*

c. Creative Energy Consulting disagreed with the proposition: *"the AOB will take several decades to converge towards a TPS [tilted postage stamp] price profile, creating a large amount of inefficiency in investment and behaviour in the meantime (and ultimately a less efficient long-term outcome)"*.

d. Houston Kemp appear to disagree with the proposition. Houston Kemp said: *"…in order for customers to be able to engage with and respond to the signals that they receive, it is likely that they will need to devote substantial resources to this task. However, it is unlikely that all but the very largest customers will be in a position to understand completely the inner workings of the area of benefit calculation"*.

e. Compass Lexecon would have disagreed with the proposition: *"since the new charges aim at concentrating sunk cost recovery on fewer market participants, rather than spreading it out, they could lead to substantial inefficiencies by distorting these users' consumption and investment patterns"*.

4.2.3 Summary

240. None of the expert reports I reviewed expressed clear support for the proposition that the EA's proposals are likely to materially improve the efficiency of future investments in generation and load. One report offered limited support, while eight reports clearly disagreed.

4.3 Improved Efficiency of Transmission Investment

241. The proposition assessed in this section is that

> *The proposed guidelines are likely to materially improve the efficiency of future investments in transmission.*

242. This is an important proposition because it reflects a primary motivation for the EA's efforts to change the TPM.

4.3.1 First Issues Paper

243. I was able to discern an opinion on this proposition from seven of the expert reports submitted in response to the first issues paper: all seven were critical of the proposition.

a. Castalia had a negative opinion overall, but did offer limited support for this proposition: *"The proposed TPM could have some benefits in moving towards a more optimal combination of transmission, generation, and load investments in the future"*. However, Castalia expressed concern over investment efficiency problems, saying that the method proposed for estimating the beneficiaries-pay charge *"undermines the perceived fairness of the charge to an extent that is likely to impact on the confidence of market participants and major electricity users to invest."*

b. CEG disagrees with the proposition, saying *"the proposal will increase the scope for disputes and in a manner that may lead some parties to advocate against efficient investments (or for inefficient investments) because they care primarily about the allocation of sunk costs. This will harm dynamic efficiency"*.

c. PwC is likely to have disagreed with the proposition. PwC discussed several aspects of the question, before concluding that *"the benefits resulting from more efficient transmission investments are likely to be overstated in the CBA"*.

d. NERA appears to disagree, or at least not fully agree, with the proposition. After discussing the EA's logic, NERA said: *"it is important for this argument that those persons charged ex-post are those that saw benefits ex-ante. There are several reasons why the strength of this connection is arguable"*. Several sound reasons were then provided.

e. Reunion disagreed that investment efficiency would improve: *"we do not believe the Authority can confidently claim any dynamic efficiency benefits at all"*.

f. Frontier disagreed: *"given that the most transmission investment is motivated by the need to maintain reliability standards, it is unclear how much influence participants could have on the decision to proceed with a new transmission investment. Even if the TPM could encourage participants to get more involved in transmission investment decision-making, such incentives would seem to apply under any methodology in which a wide variety of parties were required to contribute towards the cost of new transmission investments"*.

g. Covec disagreed: *"There is no reason to expect that this structure of incentives will limit lobbying to projects that are incrementally beneficial to the industry"*.

4.3.2 Second Issues Paper

244. The only three expert reports from which I could find an opinion on this proposition were all in disagreement.

a. PwC was not convinced that the proposed TPM changes would lead to more efficient grid investment, saying *"if using mobile diesel generators truly is a cost effective means of deferring capex we would assume Transpower would do this anyway. It is not clear why this is a benefit that will be delivered only by the proposed new TPM"*.

b. Axiom disagreed with the proposition, saying: *"In our opinion, introducing an AoB charge could would not have a beneficial effect on the new investment approval process – it would have a negative impact"*.

c. Creative Energy Consulting disagreed, arguing that: *"the targeting of costs under the AOB regime is likely to have the counterintuitive effect of diminishing customer engagement in the planning process"*.

4.3.3 Summary

245. The weight of expert opinion is strongly against the proposition that the EA's proposals are likely to materially improve the efficiency of future investments in transmission. Of the ten expert reports that expressed a view on the proposition, only one was in partial support. I also note that NERA's first report appeared to disagree, despite NERA's overall support for proposal described in the EA's first issues paper.

4.4 Reduced Distortions in Grid Use

246. The proposition assessed in this section is that

> *Distortions (i.e. inefficiencies) in grid use under the existing TPM will be eliminated or materially reduced.*

247. This proposition relates to "static" efficiency because it concerns the use of existing assets rather than investment in new assets.

4.4.1 First Issues Paper

248. I was able to discern an opinion on this proposition from six of the expert reports submitted in response to the first issues paper: all six disagreed with the proposition.

a. Castalia disagreed, arguing that by charging retailers for (volatile) benefits, the proposal would increase retail prices and that *"as well as being inefficient, allocating SPD charges to retailers will also create a barrier to new entry by increasing retail risks"*.

b. CEG disagreed, devoting section four of its report to analysing *"the ways in which the proposal could compromise the efficiency of the wholesale spot market dispatch process by causing generators to adjust their bids so as to avoid the incidence of transmission charges, resulting in higher spot prices"*.

c. PwC disagreed *"the proposal could distort the economic efficiency of the wholesale market system by introducing consideration of sunk transmission costs into otherwise efficient SRMC pricing decisions"*.

d. NERA disagreed: *"the EA's scheme reduces static efficiency"*.

e. Redpoint disagreed: *"these inefficiencies will likely increase wholesale electricity prices, an increase that will be passed onto the end consumer"*.

f. Covec disagreed: *"we would expect that retail electricity prices will increase by more than the sum of the beneficiary pays charges, and that the intensity of retail competition will fall somewhat"*.

4.4.2 Second Issues Paper

249. The only three expert reports from which I could find an opinion on this proposition were all in disagreement.

a. PwC appeared to disagree: *"transmission customers still have incentives to try to avoid an allocation of some (ie AoB) sunk costs. It is not clear why it is efficient to be able to avoid AoB sunk costs but not residual charge sunk costs".*

b. Axiom disagreed with the proposition: *"even if customers could accurately predict their AoB charges, and safely ignore the actions of other customers, there is no basis to presume they would make efficient consumption and investment decisions. Private benefits are not synonymous with forward-looking costs. The AoB charge might instead cause load and generation to make inefficient consumption and investment decisions, and hinder the new investment process".*

c. Compass Lexecon argued that the proposal would increase retail electricity prices (which would reduce usage, so I infer disagreement with the proposition), relative to a minimally-distorting TPM. *"We estimate that under the EA's proposal, retail prices would increase between $2.5/MWh and $3.95/MWh, increasing current residential electricity prices in the range of 1-1.5%. On the other hand, the implementation of a TPM that satisfies basic principles for sunk cost recovery could reduce retail prices to consumers in New Zealand in the range of 2-3% relative to the current residential electricity prices, via a reduction in transmission charges paid by line companies".*

4.4.3 Summary

250. I found ten expert reports that expressed a view on this proposition: all were in disagreement.

4.5 More Durable

251. The proposition assessed in this section is that

The proposed guidelines will be more durable than the status quo.

4.5.1 First Issues Paper

252. I was able to discern an opinion on this proposition from five of the expert reports submitted in response to the first issues paper: all five disagreed with the proposition.

a. Castalia disagrees: *"It is far from clear that the proposed TPM does in fact provide a lasting solution that will not be subject to further debate, and further debate may in fact have considerable value".*

b. CEG disagrees: section three of the CEG report *"explains why the proposal is unlikely to reduce the scope for disputes and ongoing lobbying in the manner intended".*

c. PwC disagrees with this proposition. After considering several aspects, PwC concluded that *"lobbying issues associated with the proposed TPM are therefore likely to be enduring".*

d. Redpoint disagrees: *"the methodology used in allocating charges to beneficiaries may result in more disputes when new investments in new transmission assets are proposed".*

e. Frontier disagrees: "*the calculated benefits of transmission assets under the Authority's approach are completely artificial. As such, pressures to change the methodology in the future would remain*".

4.5.2 Second Issues Paper

253. In response to the second issues paper, two of five experts supported the proposition.

a. PwC expressed concern that the proposed TPM would lead to disputes, saying: "*the novelty of the arrangements, the level of discretion and the financial impacts on transmission customers make disputes a near certainty*".

b. Stephen Littlechild agreed with the proposition, saying: "*The new arrangements proposed by the EA, notably pricing that reflects costs and benefits and treatment of HVDC consistently with other transmission assets, are more consistent with a competitive market sector. In that sense, they are more durable than the present arrangements*".

c. NERA agreed with the proposition, saying: "*By materially improving the alignment of transmission costs and benefits, the Authority's TPM proposal would improve the durability of the regime*".

d. Axiom doubted the proposition, saying: "*it is quite possible that the proposed design of the AoB charge would increase ongoing costs unless it is modified….The potential for ongoing controversy is clear – particularly (and perhaps somewhat ironically) if more complex methodologies are employed*".

e. Creative Energy Consulting disagreed with the proposition, emphasising the fact that by basing the AoB charge on historic usage, this charge would become increasingly disconnected from current usage. "*The EA emphasizes the need for durability and this is perhaps the least durable kind of charge, because the unfairness and regret continues to grow year by year*". Creative Energy Consulting also criticised the durability of the proposal more generally: "*…by including some historical assets, but not others, within the AOB regime, by drawing a "line in the sand", the EA has just created some new grounds for claims of unfairness: for example, from customers in Northland, who appear to be paying for the majority of the cost of the assets that serve their region, through the new AOB charge and, in addition, a share of the older assets serving all other regions, through the residual charge*".

4.5.3 Summary

254. Ten expert reports commented in whether the EA's proposals would result in a more durable TPM: eight disagreed; two agreed.

4.6 No Unintended Consequences

255. The proposition assessed in this section is that

There are no unmanageable or unacceptable unintended consequences likely to arise from an area of benefit (AoB) charge.

4.6.1 First Issues Paper

256. I was able to discern an opinion on this proposition from four of the expert reports submitted in response to the first issues paper: all four disagreed with the proposition.

a. Castalia disagrees with the proposition, saying: *"the proposed TPM would also have significant unintended impacts on the wholesale and retail markets that will reduce efficiency"*.

b. CEG disagrees with the proposition, saying: *"shifting the financial burden of past sunk costs does not offer any obvious efficiency benefits, and risks giving rise to unintended consequences"*.

c. NZIER disagrees with the proposition, saying: *"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"*.

d. Redpoint disagrees with the proposition, saying that it *"will be challenging to implement a TPM similar to that proposed by the EA without significant unintended consequences"*.

4.6.2 Second Issues Paper

257. My examination found four experts expressing views contrary to the proposition and none supporting it.

a. NZIER considered that the main unintended consequence associated with the second set of proposals is *"future pressure to change the method of allocating the residual caused by the use of cost allocators based on historical measures without any clear description of a mechanism of how these allocators will be adjusted to respond to changes in future demand patterns"*.

b. Axiom cited several specific unintended consequences and was unable to *"rule out the possibility that the proposed allocators would result in adverse, unintended reactions from the load customers upon whom the charges are levied"*.

c. Creative Energy Consulting would disagree with the proposition. In analysing the the backward-looking basis for AoB and residual charges, CEC argued that entry decisions by electricity users could be distorted and concluded that *"these perverse incentives might, again, be mitigated using a PDP, but this might then make it hard for Transpower to charge new customers at all: whether distribution-connected or transmission-connected"*.

d. Compass Lexecon would disagree with the proposition, arguing that *"drastically changing the TPM in an ex-post fashion generates substantial uncertainty about New Zealand's regulatory stability"*.

4.6.3 Summary

258. Ten expert reports were identified as commenting on whether there are likely to be material unintended consequences arising from the EA's proposals: all ten saw risks of material unintended consequences.

4.7 Consistent with International Best Practice

259. The proposition assessed in this section is that

The proposed approach is consistent with international best practice.

4.7.1 First Issues Paper

260. I was able to discern an opinion on this proposition from four of the expert reports submitted in response to the first issues paper: I consider that all four disagreed with the proposition.

   a. CEG disagrees with the EA's claimed international precedent, stating that *"the cited international precedent does not support the re-pricing of past investments – in fact, the US Court of Appeal judgment cautions against doing so"*.

   b. It is possible that NERA also disagrees: *"this approach differs from other jurisdictions most materially by the inclusion of the benefit of the asset as a charge to market participants"*.

   c. Redpoint disagrees: *"We are aware of no international precedent for the strict allocation of transmission charges to beneficiaries across both generation and load on a period to period basis that is proposed in NZ"*.

   d. Frontier disagrees: *"beneficiaries-pay transmission charging frameworks in place internationally incorporate a decision rights regime. This means that those parties deemed to be beneficiaries from transmission investment have some ability to veto those investments. The Authority says it cannot provide for deemed beneficiaries to have input on whether investments proceed because the Commerce Commission has the responsibility for managing the investment approval process. In our view, this is an unsatisfactory outcome. Until it is resolved, the case for imposing a beneficiary pays-style transmission charge is deeply compromised"*.

4.7.2 Second Issues Paper

261. Most experts submitting on the second issues paper were silent on this proposition: one was coded as being negative.

   a. Castalia would not agree with the proposition, in my opinion. Section 4.1 of Castalia's expert report contains detailed comparisons of AoB-type charging in other jurisdictions, and falls well short of supporting the proposition.

4.7.3 Summary

262. I found no support in the expert reports for the proposition that the EA's proposals are consistent with international best practice: five expert reports were identified as commenting negatively on this proposition.

5 Details of the Proposal

263. I turn now to consideration of a set of propositions relating to the detailed design of the EA's proposals for the TPM. The views of expert submitters are assessed against eight specific propositions.

5.1 Reasonable Selection of Assets for AoB Charge

264. The proposition assessed here is that

> *The selection of a subset of interconnection assets (including the HVDC assets) for inclusion in the AoB charge is a reasonable approach and/or will result in improved efficiency and/or more equitable outcomes.*

265. From the beginning of the EA's efforts to reform the TPM, there has been a tension between the EA's forward-looking objectives for efficient use of the grid and efficient investment in the grid, and its desire to change the way grid users are charged for pre-existing assets. In both the first and second issues papers, the EA proposed recovering the cost of pre-existing assets installed since 2004 in the AoB charge, though different investment cost thresholds were used (see ¶ above).

266. Many experts have raised concerns with this approach. The citations that follow give a sense of the breadth and diversity of these concerns, which can be broadly summarised as arguing two main points. The first is that re-allocating the costs of existing assets to beneficiaries does not, of itself, lead to more efficient future usage of the grid or investment in grid-related assets. Secondly, experts argue that the proposed re-allocation of costs undermines valuable qualities for a regulatory regime, including certainty and a reputation for honouring previous commitments.

267. Since the weight of expert opinion is against the inclusion of existing assets in a new AoB charge, it will be helpful to begin this section by examining those expert submissions that were broadly supportive of the EA's proposals.

   a. NERA, in responding to the first issues paper, supported a Ramsey pricing approach to funding sunk assets and appeared to prefer a forward-looking approach to pricing for the grid, saying *"the [Ramsey] approach implies that the financial charges for **investment in-place** should be levied on peak usage; since these peaks occur at or close to grid capacity and at times of peak demand they signal relative lack of demand response"* (emphasis added). I interpret this as an endorsement of the existing interconnection charge and as disagreeing with the EA's proposal to include pre-existing assets in the AoB charge. Nothing in the balance of this NERA report weighs against that view.

   b. In responding to the second issues paper, a different NERA project team stated, without elaboration that *"the … beneficiaries-pay proposal is now forward-looking – in contrast to the earlier backwards-looking SPD proposal"*. It seems likely that this statement refers to the EA's use of forecast future market outcomes, rather than observed market outcomes, as was the case for the first issues paper proposal. Citing extensively from the EA's second issues paper, NERA then says that *"there is a dynamic efficiency reason for altering the regime on existing grid assets. While those assets* *are sunk, how they are recovered does alter forward-looking behaviour"*. Of the two alteration options that it contemplates, NERA concludes that the EA's preference is *"reasonable"* because: *"it would result in an allocation of costs that better reflects benefits; and it might result in a "more fixed" charge"*.

c. Professor Littlechild commented at some length on "application B", which was the EA's response in its TPM Options working paper to considerable adverse expert comment, over the retrospective re-allocation of the costs of pre-existing assets. Clearly in favour of the EA's proposal to include pre-existing assets, Professor Littlechild argued that *"price signals will be more informative if they are based on past as well as new transmission investments, rather than on new transmission investments only"* and that market participants might not be surprised by the proposal: *"although the precise nature and timing of the present EA proposals may not have been foreseen in detail, nonetheless prudent investors would have allowed for the possibility, perhaps even the probability, of something along these lines before too long"*.

268. While Professor Littlechild and NERA (in its second report) both broadly endorsed the EA's desire to include the cost of pre-existing assets in the AoB charge, all other experts commenting on this point took issue with the EA's approach.

5.1.1 First Issues Paper

269. In addition to the NERA report discussed above (¶267.a) which opposed the proposition, the following expert views on this matter were submitted in response to the EA's first issues paper.

a. Castalia said: *"if the allocation is based on the projects that have been constructed post 2004, the impact of the SPD charge may be inequitable"*.

b. CEG expressed concern about the beneficiaries-pay approach and added *"seeking to apply the approach to past investments would entail even more controversy"*.

c. PwC said that *"the proposal could distort the economic efficiency of the wholesale market system by introducing consideration of sunk transmission costs into otherwise efficient SRMC pricing decisions"*.

d. Redpoint said: *"changing the way that the costs of existing assets are recovered cannot, of itself, have any positive impact on the efficiency of new transmission investments*".

e. Frontier said: *"given the indirect link between network users' decisions and transmission investment decisions, there is nothing intrinsic to a beneficiary pays approach as applied to existing transmission assets that ensures economically efficient outcomes"*.

f. Covec said: *"ignoring sunk costs is a basic principle of efficient decision-making. Yet the proposal to constantly re-assess charges for sunk assets means that when participants consider a new grid investment they will have one eye on their benefit charge for that asset, and the other eye on the impact that asset will have on all of their existing benefit charges. There is no reason to expect that this structure of incentives will limit lobbying to projects that are incrementally beneficial to the industry*".

5.1.2 Sunk Costs Working Paper

270. Recognising the heavily negative feedback on the question of whether to re-allocate obligations for the costs of pre-existing assets, the EA released a stand-along working paper that sought to defend its position on the topic. A central theme of this working paper was that there is a distinction between fixed costs and sunk costs. Four expert reports were submitted in response, two of which commented (negatively) on the proposition at issue.

a. Castalia said: *"the core disagreement between the Authority and submitters throughout the TPM review process… is whether there can be material dynamic efficiency gains from changes in behaviour by reallocating transmission costs… it is clearly not sufficient to hold the view that dynamic efficiency gains (however uncertain) will outweigh any loss in static efficiency"*.

b. CEG said: *"we have observed on a number of occasions that the EA's proposal to reallocate the costs of past investments (whether defined as sunk, fixed or otherwise) using a "beneficiaries-pay" approach is highly unlikely to promote static or dynamic efficiency"*.

5.1.3 TPM Options Working Paper

271. As the EA developed its thinking in the lead-up to its second issues paper, it published a TPM Options working paper that tested some of its ideas. All of the options in that working paper included the re-allocation of obligations for the cost of existing assets. However, this was also the first time that the EA raised the prospect of withdrawing from its plan to include assets installed since 2004 (which it referred to as "Application A"), and contrasted this with the idea of only applying the new AoB charges only to new investments ("Application B"). The following comments are noted from expert submissions on this working paper.

a. James Bushnell, referring to the AoB charge as a supplemental charge said *"it would be inappropriate to use such supplemental charges to recover the costs of investments that have already been made. This could only distort current behavior, and have no impact on the grid investment itself as those investments, and their costs, are sunk. Therefore, the goal of economic efficiency is best served by the "Application B" option, which would place less capital costs from existing investments under the new pricing regime"*. Also: *"it is hard to escape the conclusion that the application B proposal dominates with respect to economic efficiency"*.

b. Castalia said *"we find that under Application B the charges being considered by the Authority have the same or better efficiency impacts than Application A for a DCC, or an AoB or SPD charge. The reasons for the differences in expected efficiency impacts are described below—in essence changes stem from the fact that applying the charges to new assets only ensures that price signals are only sent to parties that can change their behaviour to reduce transmission costs"*.

c. CEG said: *"if the EA believes that a more efficient – and fairer – allocation of charges might be obtained by changing the allocation of sunk costs, but that Application A would result in "too much" rebalancing, then transition mechanisms are not the solution. Rather, an alternative approach is required"*.

d. Compass Lexecon disagreed with the proposition, saying: *"dynamic efficiency, however, is independent of how the costs of historical investments are recovered. Hence, there are no efficiency gains from including historical assets on the application of the new and more "targeted" charges. On the contrary, this approach goes against the wide base rule for optimal taxation".*

e. Creative Energy Consulting said: *"planning efficiency cannot be improved retrospectively, and so the beneficiary-pays methods intended to promote this objective should also not be retrospective…. Therefore, based on the Authority's own assessment framework, application B is to be preferred".*

f. PwC queried the 2004 cut-off date: "*The basis for the 2004 cut-off is not strong and undermines the Authority's case for changing the allocation of post-2004 investments.*"

g. NZIER were uncertain about the proposition, saying: "*the mechanisms to reallocate grid costs proposed by the Authority under Application A appear to have the potential to improve the clarity of signals to grid users about the costs of access to the grid and therefore to improve the efficiency of grid use and possibly investment decisions. The caveat on this statement is that the proposed changes still require current grid users to pay for unused capacity*". I consider that NZIER does not express a view either way on the proposition.

5.1.4 Second Issues Paper

272. In its second issues paper, the EA dropped usage of the terms Application A and Application B but effectively retained the Application A proposal, being the inclusion (subject to size thresholds) of assets installed since 2004 in the calculation of the AoB charge. Several expert reports were silent on this aspect of the proposal. I found the following specific commentaries.

a. PwC disagreed with the proposition: *"The AoB charge, if introduced, should apply only to new assets (ie assets commissioned after the date the TPM guidelines are published) with a value of more than $20m. This would be consistent with Transpower's major capex IM".*

b. Professor Littlechild supported the proposition. *"If the proposed new TPM is applied to previous transmission investments, not least the HVDC interconnector, that will provide a better idea of whether – and to what extent – those investments were appropriate when they were made. And that knowledge will enable more accurate forecasts to be made in future, when new transmission investments are considered".*

c. NERA supported the proposition: *"there is a dynamic efficiency reason for altering the regime on existing grid assets. While those assets are sunk, how they are recovered does alter forward-looking behaviour".*

d. Axiom disagreed with the proposition. *"There can be no dynamic efficiency benefits gained from signalling to generators that it is cheaper for them to locate in areas where assets are 'older'. Regardless of whether assets are old or new, their costs are sunk. This distinction can therefore only give rise to dynamic inefficiency. More generally, we not aware of any international transmission pricing arrangements that involve the reallocation of past sunk costs".*

e. Creative Energy Consulting disagreed with the proposition. *"…by including some historical assets, but not others, within the AOB regime, by drawing a "line in the sand", the EA has just created some new grounds for claims of unfairness: for example, from customers in Northland, who appear to be paying for the majority of the cost of the assets that serve their region, through the new AOB charge and, in addition, a share of the older assets serving all other regions, through the residual charge"*.

f. Compass Lexecon disagreed with the proposition. "*Dynamic efficiency, however, is independent of how the costs of historical investments are recovered. Hence, there are no efficiency gains from including historical assets on the application of the new and more "targeted" charges. On the contrary, this approach goes against the wide base rule for optimal taxation"*.

g. Professor Yarrow provides a lengthy rebuttal of Professor Littlechild's view, and in so doing clearly disagrees with the proposition. *"Application B (or an alternative approach that reflects outcomes in relevant, workably competitive markets in a similar way) has the following, two attractive features: Its adoption would signal that the EA has been relatively unresponsive to past lobbying…; and Its adoption would signal that the potential gains from lobbying (aimed at securing redistributive benefits in future policy exercises) could be expected to be lower than has previously been the case"*.

5.1.5 Summary

273. My review of expert reports submitted since 2012 shows twenty expert reports opposing the EA's proposal to include assets installed since 2004 in the AoB charge, with two in favour: Professor Littlechild and NERA's second report.

274. In my opinion, neither of the two supporting expert reports provides a convincing argument in support of the proposition.

a. Professor Yarrow identifies four lines of argument in Professor Littlechild's report and supplies well-reasoned counter-arguments to each. This is followed in Professor Yarrow's report by three reasons for restricting the scope of the AoB charge to new investments only, i.e. for opposing the proposition at issue. Having examined these reports closely I strongly prefer Professor Yarrow's positions.

b. NERA's second report support for the proposition (¶272.c) is undermined by its earlier clear preference for using peak demand charges to recover the cost of pre-existing assets (¶267.a). No attempt is made to reconcile these views in NERA's second report. Instead, NERA outlines just two potential improvements to the TPM and prefers the EA's because: *"it would result in an allocation of costs that better reflects benefits; and it might result in a "more fixed" charge"*. I did not find this argument at all convincing for several reasons: there are more than two options; there are major challenges in reflecting benefits through charges; and there are also serious challenges to the "fixedness" of the AoB charges under the EA's proposal.

275. The core argument in favour of re-allocating the cost of existing assets is that doing so changes grid usage in ways that will lead to better grid investment decisions in the future. This relies on the view that the grid investment process controlled by the Commerce

Commission is currently, or soon will be, creating an inefficient pattern of grid investment; a claim that appears to lack evidentiary support.

276. Creative Energy Consulting has argued that if such a re-allocation really is needed to improve the efficiency of future grid investment, there is no obvious reason to limit it to assets installed since 2004. I note that in the December 2016 Supplementary Consultation, the EA proposes that *"Transpower must include in the TPM a method for extending the AoB charge to more historical assets than proposed in the second issues paper if doing so is practicable and consistent with the requirements of clause 12.89 of the Code"*. However, Creative Energy argues that if all assets were to be included, it would be more efficient to move directly to the long-run solution that an AoB charge would end up mimicking, which is a tilted postage stamp.

5.2 Accurate Assessment of Beneficiaries

277. The proposition assessed in this section is that

There is a mechanism for accurately assessing the lifetime beneficiaries of shared assets.

278. This has been a matter of contention since the first issues paper, which proposed a specific method for identifying beneficiaries and identifying their benefits. There are two concerns expressed by the experts: one is over the near-term estimation of benefits; the second is over the fact that the benefits of each customer group change over time.

5.2.1 First Issues Paper

279. The following views are noted in response to the first issues paper.

a. Castalia disagreed with the proposition: *"the charges generated by the SPD method are not proportional to the benefits received"*.

b. CEG disagreed with the proposition: *"even if this (or a similar) approach is applied only to new investments in interconnection assets, the potential for distortions is considerable. This would be unavoidable given the fact that this assessment would decide "once and for all" who was going to pay for the asset"*.

c. NZIER disagreed with the proposition: noting three *"significant… structural issues"* being: *"the half hour capping period used in the benefits calculation that is instrumental in limiting the extent to which beneficiaries can be identified; the unorthodox calculation of consumer benefits that has the impact of overstating the quantum of the benefits; the 2004 cut-off date for inclusion of assets in the SPD scheme seems to be expedient"*.

d. PwC disagreed with the proposition: *"the SPD charge reveals only the benefit of existing assets not future investments"*.

e. Marsden Jacobs did not state a clear opinion. Noting that there were a number of challenges, the Marsden Jacobs said *"while MJA agrees with the authority that these issues can be addressed, they raise many issues in relation to the meaning and appropriateness of benefits calculated via this approach"*.

f. Redpoint disagreed with the proposition: *"ignoring the variation of benefits with time may result in a significant mismatch between the allocation of transmission charges and the allocation of benefits"*.

g. Reunion disagreed with the proposition, citing four reasons for its conclusion that *"The SPD method proposed by the Authority is not likely to correctly identify beneficiaries"*.

h. Frontier disagreed with the proposition, discussing short- and long-term issues and concluding that *"even if charges based on the proposed SPD-based methodology can provide a reasonable indication of the half-hourly benefits of individual transmission assets, it may not provide a good indication of the distribution of the longer term benefits of those assets"*.

5.2.2 Beneficiaries-Pay Options Working Paper

280. In its beneficiaries-pay options working paper the EA sought to respond to criticism levelled at the proposal in its first issues paper. Four new options were presented for ways to assess a beneficiaries-pay charge. Five expert views were identified from reports submitted in response to this working paper. All were in disagreement with the proposition.

a. James Bushnell disagreed with the proposition: *"If charges could be based upon offsetting benefits, and all users knew exactly what those offsetting benefits would be, and each of those users had proportional influence on the decision process, then only those projects for which the aggregate offsetting benefits exceed the costs would make it through the approval process. There are several shortcomings to this logic"*.

b. Castalia disagreed with the proposition: "*We find that an area of benefit approach is more likely to generate overall efficiency gains than the SPD options examined by the Authority"*.

c. CEG disagreed with the proposition: *"there are material problems with all four of the new options, i.e., the simplified SPD charge, the GIT-plus-SPD and SPD-plus-GIT charge, and the zonal SPD option. Many of these problems are the same or similar in nature to those we identified with the EA's original proposal"*.

d. NZIER disagreed with the proposition: *"the simple SPD proposal has not addressed some of the important issues that were identified from the 2012 proposal and it leaves a number of new design issues to be resolved"*.

e. PwC disagreed with the proposition: *"The complexity of the four proposed options, particularly compared to the status quo, remains a significant barrier to their acceptance. While we agree that new technology can facilitate more sophisticated pricing approaches, the core principles need to be cohesive, simple to understand and implement, and robust to lobbying"*.

5.2.3 TPM Options Working Paper

281. Several experts made comments relevant to the proposition when responding to the TPM options working paper. I found no expert reports that explicitly supported the proposition, and five expert reports that were either explicitly or implicitly in opposition.

a. Castalia saw difficulties with the proposition: *"we also see a practical issue in that both DCC and SPD charges allocate the costs of assets based on past behaviour or actual use of the asset. Therefore, when new assets are commissioned, it is not clear how initial charges will be set"*.

b. CEG disagreed with the proposition: *"The changes that have been made to the SPD methodology have improved the approach, but many problems remain. As we have explained at length in previous reports – and as the Options Paper acknowledges – the charge may cause generators to alter their bidding conduct in inefficient ways to reduce their exposure to it"*.

c. Compass Lexecon saw difficulties with the proposition: "*The process of identifying beneficiaries who would pay for new investments is not an easy task. This process is usually based on a physical concept: a network user is considered a beneficiary if it is located on a node where electricity flows will change as a result of the new investment. Note that physical flows are an imperfect measure of benefits, as these are not only determined by flows but also by price and quantity movements. It could be the case that an identified beneficiary using the electricity flows method is not receiving economic benefits at all. Conversely, it could also be the case that given the grid configuration, an agent who receives economic benefits from the expansion, is not identified as beneficiary using the electricity flows analysis, giving rise to a free riding problem"*.

d. Creative Energy Consulting disagreed with the proposition: *"the allocation of charges to the demand side is based on an allocation of capacity that is arbitrary and inequitable; and the allocation of charges to the generation side is based on output which will degrade efficiency, compared to Ramsey pricing best practice"*.

e. PwC disagreed with the proposition: *"under AoB, charges are allocated to particular groups of customers, e.g. North Island consumers or South Island generators. The participants within these customer groups will change over time. If a major generator closes or a major load customer exits the market then all other customers in that group will see their charges increase. This means parties will be subject to random fluctuations in their AoB charges which are entirely unrelated to their own patterns of use"*.

5.2.4 Second Issues Paper

282. I found only five expert reports submitted in response to the second issues paper that commented directly on the proposition at issue. All five were negative, and they included two expert reports that were broadly supportive of the EA's proposals.

a. PwC disagreed with the proposition: *"the Authority has stated that the "AoB is easy to calculate once the benefits have been estimated". This may be true, but estimating the benefits is the challenge and it should not be implied this will be easy"*.

b. Professor Littlechild, while broadly endorsing the EA's proposals did, in my opinion, disagree with this proposition: *"it is not always straightforward to demonstrate or quantify long-term benefits"*.

c. NERA, while broadly endorsing the EA's proposals did, in my opinion, disagree with this proposition: *"it is not necessary to aim for a high level of precision in identifying* *beneficiaries and benefits in order to achieve material efficiency gains over the status quo TPM. Indeed, there are likely to be diminishing returns to accuracy, and increasing transaction costs".*

d. Axiom disagreed with the proposition: *"private benefits are not synonymous with forward-looking costs. The AoB charge might instead cause load and generation to make inefficient consumption and investment decisions, and hinder the new investment process".*

e. Scientia disagreed with the proposition on practicality grounds: *"very significant design and implementation issues exist with the modelled AoB approach which we believe affects its ability to be used as a practicable, stable and credible process for Transpower to allocate transmission costs to its customers".*

5.2.5 Summary

283. Since the first issues paper was published, I found twenty-two expert reports that disagreed with this proposition and none that agreed. The only two submissions on the second issues paper that broadly supported the EA's proposals both disagreed with this proposition.

5.3 Fixed Capacity Measure is Appropriate for AoB and Residual Charges

284. The proposition considered here is that

The default allocation method for the AoB charge and the allocation method for the residual charge should be based on a measure of fixed capacity.

5.3.1 TPM Options Working Paper

285. The TPM Options working paper was the first time the EA proposed allocating the beneficiaries pay and residual charges on the basis of fixed capacity. There was only limited comment on this proposition from experts responding to the TPM Options working paper.

a. Castalia's view was not entirely clear, but I recorded it as being opposed to the proposition on the basis of the following comments regarding the residual charge: *"Distortions are created by calculating charges for load in a different manner than for EDBs… While the rationale for the attribution mechanisms is to avoid an incentive to control peak demand, a more equitable or consistent approach is likely to be possible".*

5.3.2 Second Issues Paper

286. In response to the second issues paper I identified three expert reports that opposed the proposition and one in support.

a. PwC disagreed with the proposition as it applies to the residual charge: *"the proposal that changes to physical capacity should not be reflected for, say, 10 years, means the allocation of residual charges may not reflect the actual service being supplied or costs being incurred".* PwC also expressed reservations about the ability of the proposal to induce efficient entry and/or exit: *"where distributors have seen a large decrease in load over that* *time (eg due to the exit of large customers) setting charges based on the average gross AMD will over-state that distributor's AMD".*

b. NZIER disagreed with the proposition: *"The EA proposal to use an historical allocator that is not varied over time nullifies the value of either the RCPD or the AMD charge as a signal to consumers to change their use of electricity at peak periods"*. Also: *"the use of an historical allocator without clear provision for adjusting the allocator over time in response to either changes in usage by individual consumers or optimisation of AoB charges introduces a rigidity into the allocation of the residual that may make the methodology less durable"*.

c. NERA was uncertain of the EA's intentions regarding the allocators for the AoB and residual charges, discussing several potential concerns, including a potential inefficiency in respect of exit: *"a low market-share (potentially) disconnecting customer may exit inefficiently earlier than otherwise"*. NERA also noted a risk with new entry but expressed no opinion: *"The mechanism could deter efficient entry if in fact the new customer would not cause any new grid costs, although the Authority considers this risk to be low"*.

d. Axiom expressed reservations about the proposition: *"Depending upon how AoB charges are assigned to new customer, it might affect the size and/or nature of the plant that is installed, e.g., a generator might decide to install a smaller plant to avoid paying a higher AoB charge. It may also cause new entrant generators to build in sub-optimal locations"*.

e. Creative Energy Consulting disagreed with the proposition: *"The fixed charging objective creates several new dilemmas for the TPM design. What about new customers arriving after the investment has occurred? What if the expected benefits from the investment don't eventuate? Can the charges really stay fixed for the life of the asset (ie 30 years or more) or do they have to be reset at some point? If there is to be a reset, when does this happen and how do you stop customers anticipating it? It's a mess. Fixed charges are not commonly used in markets, with good reason"*. Creative Energy Consulting also expressed concerns over efficient entry, concluding that *"new, large consumers who are contemplating direct connection to the transmission network are likely to opt for a distribution connection instead: or even, plausibly, a connection to an existing, grid-connected consumer's supply network"*.

5.3.3 Summary

287. While not heavily commented upon, the weight of expert opinion disagreed with this proposition: five expert reports disagreed and one was uncertain.

5.4 Cost Allocators are Appropriate

288. The proposition considered in this section is that

It is sensible and consistent with the EA's statutory objectives to remove the RCPD charge.

5.4.1 TPM Options Working Paper

289. Two expert reports commented on this proposition in response to the TPM Options working paper.

a. Castalia was undecided on the proposition: *"It is unclear whether the combination of charges that potentially provide stronger price signals (DCC, AoB, LRMC, SPD) and an incentive-free residual actually provides better price signals overall than current RCPD and HVDC charges"*.

b. CEG disagreed with the proposition: *"there are potentially compelling reasons to maintain the existing RCPD charge. For example, the number of periods over which it is measured can be periodically reviewed and adjusted depending upon the circumstances at the time, i.e., it can be readily adapted to send an appropriate price signal"*.

5.4.2 Second Issues Paper

290. In response to the second issues paper five expert reports made comment on this proposition.

a. James Bushnell appeared to disagree with the proposition, concluding a discussion of the matter with the following statement: "*One should not lightly dismiss the value of a useful proxy metric, such as net peak usage, that is straightforward and transparent to measure, for the allocation of costs and benefits, particularly if it reasonably captures the conditions triggering those costs"*.

b. PwC disagreed with the proposition: *"the current RCPD price signal may be too strong … but the removal of any price signal parties can respond to goes too far"*.

c. NERA agreed with the proposition, stating that it was reasonable to assume that: *"The AoB and residual charges would be less distortionary than the existing RCPD and … HVDC charges"*.

d. Axiom disagreed with the proposition: *"by removing the RCPD-based charge, the proposal would take away the only explicit price signal that Transpower has at its disposal under the current TPM to incentivise load shedding when capacity constraints re-emerge in the future. As we explained in the previous section, and in more detail below, a shadow price would not be as effective for this purpose. The potential consequence of this could be inefficient consumption decisions in the long-run"*.

e. Creative Energy Consulting disagreed with the proposition: *"I can see two advantages in continuing to use the RCPD measure, rather than reverting to a simple AMD measure, as the EA proposes. Firstly, based on Transpower's work, the RCPD measure is more efficient than AMD. … Secondly, since the RCPD measure is used currently, continuing to use this measure will reduce somewhat the amount of price shock created in the move to the new regime. Such shocks are undesirable since they raise the perceived level of regulatory risk in the industry and also can adversely affect price-sensitive users"*.

5.4.3 Summary

291. Of the seven expert reports commenting on this proposition, six were clearly in disagreement; one agreed and one did not express a clear opinion.

5.5 Appropriate to Include DER in Capacity Assessment

292. The proposition considered in this section is that

The inclusion of DER in the capacity assessment for the residual charge is appropriate.

5.5.1 Second Issues Paper

293. The Authority proposed that output from DER should be added back in to networks' and users' assessments of "gross" capacity in determining allocations of charges. I only found two expert reports that commented on this proposition, both in response to the second issues paper. Both of these reports disagreed with the proposition.

a. PwC disagreed with the proposition: *"as a minimum, the assessment of physical capacity for the residual charge should be net of installed or consented distributed generation as this generation may have been built to minimise transmission costs"*.

b. NZIER saw practical difficulties with the proposed approach: *"the definition of gross AMD suggested in TPM is also likely to be difficult to implement as it would require all direct connect customers to provide accurate data on their historical use of demand response and embedded generation and presumably some evidence to verify this data"*.

6 Conclusions

294. The source materials for this review show that the EA has consistently sought to do three things: abandon the current separate charge for the HVDC link; create new transmission charge based on the benefits of individual transmission investments; and extend this beneficiaries-pay charge to existing grid assets approved since 2004. These goals have also been consistently linked together: the EA has always proposed that the costs of the HVDC link be included in its asset-based beneficiaries-pay charge.

295. These three consistent goals did not emerge from a disciplined policy development process. This is most apparent from reading the first issues paper (October 2012) in which the EA did not separate its review of the existing TPM Guidelines from its proposals for change. The first issues paper described the problem the EA was addressing as the absence of the solution it preferred. This approach left readers unclear as to whether a review had actually been undertaken. Moreover, it was not until September 2014, after a further seven working papers had been issued for consultation, that the EA explicitly consulted on its problem definition.

296. While the problem definition was sharpened somewhat as the review progressed, substantial criticisms remained. Over time, expert arguments against the (evolving) problem definition focussed more heavily on the EA's description of the interconnection charge problems and the durability problems, and on the EA's estimates of the scale and materiality of problems.

297. Alongside these concerns about the problem definition, experts have been very critical of the EA's proposed beneficiaries-pay charges, including the core features of asset-level benefit charging, and the inclusion of pre-existing assets, which have remained in place since the first issues paper in October 2012. Carefully drafted expert reports have examined in detail the way these proposals are likely to affect the conduct of grid users, and concluded that there are serious problems with the EA's analysis.

298. The EA has modified its proposals over this period but remained firmly in favour of highly detailed asset-level estimation and allocation of benefits, and firmly in favour of extending beneficiaries pay charges to pre-existing assets approved since 2004.

299. I have been left with the impression that the EA has not been heavily influenced by the criticism these experts have made of its proposals. While there have been many consultation papers since October 2012, and the proposals have changed over that time, the EA remains firmly committed to the original two underlying goals. Indicators for this conclusion include:

a. NZIER, which has been much less critical of the EA's proposals than many experts, noting in response to the second issues paper the curious fact that "*the application of the same set of 'decision-making and economic framework' in TPM1 and TPM2 principles has led to a markedly different allocation of costs between EDBs and direct connect industrials*".

b. Despite years of work to refine and explain the proposals, the expert reports are unanimous (12 – 0) in disagreeing with the proposition that *"the EA has established that an AoB charge will send desirable price signals*".

c. By far the most rejected proposition I have assessed, is the most fundamental of all of the propositions, that *"the AoB charge is superior to the alternatives"*. My review found unanimous (32 – 0) disagreement on this point in the expert reports.

300. As an independent regulator, the EA is expected to stand-up to vested interests when that is necessary to fulfil its statutory obligations. So the *volume* of criticism identified in this review should not necessarily be determinative. Instead, the EA is obliged to dispassionately weigh up the evidence in reaching its determinations. Often this weighing up process is reflected in a regulator's consultation papers, including with citations to submissions making the arguments that are being weighed up.[21]

301. For the most part, the EA's style throughout this process has been to avoid citing particular critics. Instead it has tended to refer to "submissions" in the aggregate, without identifying particular arguments made by individual experts, claim they have been considered and then reiterate the EA's view. This style is unfortunate in the current context, where there is a substantial weight of expert opinion that opposes the EA's desires: it suggests that the EA is not actually engaging with the submissions.

302. To illustrate this point, consider the question of whether AoB charging should apply to new assets only (Application B) or to all assets installed since 2004. I choose this topic because it is one of the few on which the EA has engaged substantively with expert submissions. Prior to the second issues paper, expert opinion on this question was unanimously (15 – 0) against including pre-existing assets. Those fifteen expert reports argued (see section 5.1 above) that there were no clear dynamic efficiency benefits from such backdating on a beneficiaries-pay basis, but clear static efficiency losses. The EA's second issues paper responded (at ¶5.97 – 5.98):

> *"the dynamic efficiency gains from applying such pricing to historical assets are restricted to future modifications of those assets, and so are much weaker than implied in paragraphs 5.91 to 5.96 above. Arguably, therefore, in these circumstances a stronger emphasis should be placed on allocative efficiency, and so a greater focus on approximations to 'lump sum' charges for recovering the cost of those investments. Nevertheless, the Authority is of the view that there are good reasons to apply service-based and cost-reflective pricing approaches to recent major historical investments as well as future investments"*

303. Despite the EA's attempt to justify this position, a (5 – 2) majority of experts commenting on the second issues paper remained unconvinced. I have explained above (¶274) why I agree with the majority.

304. A second and rather stark example concerns the EA's arguments over the durability of the TPM. Throughout the period under review, the EA has consistently argued that its

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[21] See, generally, the consultation papers issued by the Commerce Commission during its development of Input Methodologies. These papers frequently referred to specific submissions, despite being produced under onerous timelines dictated by legislation.

preferred TPM Guidelines would be more durable than the status quo because there will be less arguing and lower costs of disputes. The experts disagree by a margin of eight to two. This is one topic on which the number of submissions seems particularly relevant. Most of the people currently arguing with the EA disagree with the EA that there will be less arguing if the EA pushes this proposal through.

305. Based on the above review and analysis I consider that the vast majority of expert opinion has disagreed with the EA throughout this review, and that the EA has not attempted to explain why it disagrees with these experts.

Appendix 1: Expert Reports Reviewed

The following expert reports were included in this review.

First Issues Paper

Castalia, Review of the Electricity Authority's Cost Benefit Analysis of the Proposed Transmission Pricing Methodology, Report to Genesis Energy, 25 February 2013.

CEG, Transmission Pricing Methodology – Economic Critique, for Transpower, February 2013.

NZIER, Transmission pricing methodology 2012, Evaluation of EA consultation paper, report to MEUG, 28 February 2013.

PwC, Submission to the Electricity Authority on Transmission Pricing Methodology: Issues and Proposal, Made on behalf of 22 Electricity Distribution Businesses, 1 March 2013.

Marsden Jacobs, Review of Transmission Pricing Methodology, Report for Vector, 1 March 2013.

NERA, Memo to Meridian Energy, 28 February 2013.

Redpoint Energy, Evaluation of New Zealand transmission pricing review against international experience, for Trustpower, 18 February 2013.

Reunion Asia Pacific, Proposed Transmission Pricing Methodology: Assessment of the CBA, Report prepared for Mighty River Power, February 2013.

Frontier Economics, TPM Review, Report prepared for Mighty River Power, March 2013.

Covec, Review of TPM Proposals, for Mighty River Power, 28 February 2013.

EPOC, Transmission Pricing Methodology: issues and proposal, 1 March 2013.

NZIER, Not time to revisit TPAG, Cross Submission for MEUG, March 2013.

PwC, Review of Submissions on the Electricity Authority's Transmission Pricing Methodology, Cross Submission for Mighty River Power, March 2013.

CBA Working Paper

Castalia, Review of the Transmission Pricing Methodology: CBA - Working Paper, Report to Genesis Energy, October 2013.

NZIER, Letter to MEUG, 9 October 2013.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: CBA, made on behalf of 22 Electricity Distribution Businesses, 15 October 2013.

CEG, Economic Review of EA CBA Working Paper, Report for Transpower, October 2013.

Sunk Costs Working Paper

Castalia, Response to Electricity Authority Transmission Pricing Methodology: Sunk Costs Working Paper, 19 November 2013.

CEG, Letter to EA, Sunk Costs Working Paper, 28 October 2013.

NZIER, Letter to MEUG, EA Consultation – TPM SUNK COST paper, 15 November 2013.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: Sunk Costs, made on behalf of 20 Electricity Distribution Businesses, 19 November 2013.

ACOT Payments for Distributed Generation

ASEC, Avoided Cost of Transmission (ACOT) payments for Distributed Generation, for Independent Electricity Generators Association, 31 January 2014.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distribution generation, made on behalf of 22 Electricity Distribution Businesses, 31 January 2014.

CEG, Avoided Cost of Transmission Payments, Report for Vector, January 2014.

Strata Energy Consulting, Report on the history of the Bulk Supply Tariff and Transmission Pricing in New Zealand, report for Trustpower, January 2014.

NERA, Regulatory Change Management, Report for Trustpower, January 2014.

Beneficiaries Pay Options Working Paper

James Bushnell, Efficiency and Cost Recovery for Transmission Network Investments, March 2014.

Castalia, Transmission Pricing Methodology: Beneficiaries Pay Options, Report for Genesis Energy, March 2014.

CEG, Economic Review of EA Beneficiaries-Pay Options Working Paper, Report for Transpower, March 2014.

EPOC, Transmission Pricing Methodology: issues and proposal, 25 March 2014.

NZIER, Beneficiaries-pay options, Report for MEUG, March 2014.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: Beneficiaries-Pay Options, made on behalf of 21 Electricity Distribution Businesses, 25 March 2014.

Connection Charges

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: Connection charges Made on behalf of 21 Electricity Distribution Businesses, 24 June 2014.

LRMC Charges

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: LRMC charges, made on behalf of 22 Electricity Distribution Businesses, 23 September 2014.

Problem Definition Working Paper

ASEC, TPM Problem Definition: Interconnection and HVDC, for Independent Electricity Generators Association, 22 October 2014.

Castalia, Transmission Pricing, Market Operations, and Investment Decisions: A Review of the Electricity Authority Problem Definition Working Paper, Report to Genesis Energy, October 2014.

NZIER, Transmission pricing problems, Assessment of the 2014 EA problem definition, report to MEUG, 28 October 2014.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology: Problem definition relating to interconnection and HVDC assets, made on behalf of 21 Electricity Distribution Businesses, 28 October 2014.

TPM Options Working Paper

ASEC, TPM Options: Treatment of loss and constraint excess, 11 August 2015.

James Bushnell, Equity and Efficiency Implications, of New Zealand's Transmission Pricing Methodology Options, August 2015.

Castalia, Transmission Pricing Options, An Analysis of the TPM Options Working Paper, report to Genesis Energy, August 2015.

CEG, Economic Review of TPM Options Working Paper, Report for Transpower, August 2015.

Compass Lexecon, Transmission pricing mechanism in New Zealand: An analysis of the Electricity Authority proposed options, 11 August 2015, for Vector.

Creative Energy Consulting, Review of Electricity Authority's TPM Options Working Paper, August 2015.

EPOC, Consultation on Transmission Pricing Methodology Review, TPM Options, 11 August 2015.

PwC, Submission to Electricity Authority on Transmission Pricing Methodology Review: TPM options working paper, made on behalf of 21 Electricity Distribution Businesses, 11 August 2015.

Scientia, Analysis of the flow tracing model to calculate deeper connection transmission charges, Report to Transpower, August 2015.

NZIER, Transmission pricing options, Advice regarding EA working paper on grid charging, Report to MEUG, August 2015.

Second Issues Paper

EPOC, Consultation on Transmission pricing methodology: issues and proposal. Second issues paper, 26 July 2016.

PwC, Submission to Electricity Authority, on Transmission Pricing Methodology Review: Second issues paper; and Distributed Generation Pricing Principles, made on behalf of 14 Electricity Distribution Businesses, 26 July 2016.

Castalia, Ensuring an Improved Transmission Pricing Methodology, Report to Genesis Energy, July 2016.

NZIER, TPM second issues paper, Advice to MEUG on TPM cost benefit analysis, 26 July 2016.

Stephen Littlechild, Report on the Electricity Authority's Transmission Pricing Methodology Review, 26 July 2016.

NERA, Transmission pricing methodology – review of second issues paper, for Meridian Energy, 26 July 2016.

Axiom Economics, Economic Review of Second Transmission Pricing Methodology Issues Paper, A report for Transpower, July 2016.

Scientia, Technical evaluation of AoB approach used in the TPM second issues paper, for Transpower, July 2016.

PwC, TPM Change Impact Assessment, Responding to the Electricity Authority's Consultation Papers, a report for Transpower, July 2016.

James Bushnell, Pricing Principles for Network Investments and Distributed Energy Resources, July 2016.

Bruce Girdwood, Transmission pricing, regulation and practice A practitioner's view, 23 July 2016.

Creative Energy Consulting, Review of the Electricity Authority's TPM Second Issues Paper, July 2016.

Houston Kemp, Review of the cost benefit analysis of the proposed TPM guidelines, Report for Trustpower, 26 July 2016.

Compass Lexecon, Transmission pricing mechanism in New Zealand: An analysis of the Electricity Authority's proposed options, 11 August 2016.

Subsequent Reports

Creative Energy Consulting, A response to Meridian's Submission to the TPM Consultation, September 2016

James Bushnell and Frank Wolak, Beneficiaries-pay pricing and "market-like" transmission outcomes, February 2017

George Yarrow, Some awkward problems raised by the Electricity Authority's Review of the Transmission Pricing Methodology, February 2017

Appendix 2: Summary CV for John Small

John applies the tools and techniques of economics to issues at the boundary between public policy and private business, and on either side of that boundary.

He has worked in all major network industries, in banking and payment systems, construction, agriculture, food processing, and on regional economic development. He is particularly interested in competition, regulation, market risk assessment, efficient contracting, and start-up businesses.

Areas of Expertise

- Expert witness
- Competition & regulatory economics
- Economic analysis of public policy
- Financial analysis
- Econometrics
- Agricultural economics

Education

PhD in economics
The University of Canterbury, 1993

BA in economics (1st class honours)
The University of Canterbury, 1990

BSc in economics
The University of Canterbury, 1989

Employment History

Founding Director
Covec, New Zealand
2001 – Present

Lay Member
High Court of New Zealand
Three 5-year terms starting 2003, 2009, 2016

Dairy Farmer
Rai Valley, Marlborough
2009 - Present

Head of Department, Economics
University of Auckland
2003 – 2004

Director
CRNEC – University of Auckland
1998 – 2004

Director
Network Economics Consulting Group, Australia
1998 – 2001

Lecturer & Senior Lecturer, Economics
Econometrics & microeconomics, University of Auckland, New Zealand
1994 – 2004

Lecturer, Economics
University of Canterbury, NZ
1993

Sample of Relevant Experience

Media Merger Analysis: Expert submissions to the Commerce Commission in opposition to proposed mergers between Sky TV and Vodafone, and between Fairfax and NZME. *For TVNZ and 2degrees, 2016.*

Competition for Currency Conversion: Expert testimony in the Australian Federal Court on conduct by Visa regarding currency conversion. *Australian Government Solicitor, 2014-15.*

Electricity Transmission Investment. Econometric analysis of cross-hedging strategy to support financing proposal for major Canada-USA merchant investment in DC transmission, *London Economics LLC, 2014.*

Fibre-Optic Network Development: Economic advisor to three (of 4) companies contracted by NZ government to build fibre-optic communications networks to the home/premises. *UltraFastFibre, Enable and NorthpowerFibre, 2014-16.*

Aviation: Expert economic submissions regarding airport pricing in general and at Nelson Airport. *BARNZ and AirNew Zealand, 2016.*

Agricultural Economics: Independent expert review of Overseas Investment Office recommendation to permit sale of Lochinver station to foreign buyers. Ministers overturned the recommendation. *Crown Law, 2015.*

California Grid Investment with Real Options: Development and application of a real options methodology for assessing grid investment proposals taking generation investment into account, with London Economics International. *California Independent System Operator, 2001-02*

Dairy Economics: Two projects advising policy officials on matters emerging from Commerce Commission review of dairy industry competition. *Ministry for Primary Industries, 2016.*

Port Sector Analysis: Analysis of asset valuations and pricing proposals by a New Zealand port, comparison with likely regulated pricing and estimation of benefits of regulation. *New Zealand Commerce Commission, 2014.*

Gas Pipeline Access & Governance: appointed to a Panel of Expert Advisors convened by gas industry co-regulator to reform gas pipeline access arrangements and investment approval processes. *Gas Industry Company, 2011-13*

Electricity Market Rules. Expert advisor on proposed change to rules governing wholesale electricity market in Australia including related party contracting and valuation of assets. *Australian Energy Markets Commission, 2012.*

Infrastructure Valuation and Cost Recovery. Expert advisor to New Zealand Commerce Commission during development of "input methodologies" that define how regulation will be applied to electricity and gas networks and airports. *Commerce Commission, 2009-10.*

Telecommunications Negotiations: Economic modelling of compensation and direct negotiations with incumbent telecommunications company to prematurely end its statutory monopoly. Work required forecasting of company profits and valuations under status-quo and competitive scenarios.
Government of Vanuatu, 2007
Government of Solomon Islands, 2009-09

Spectrum Pricing: Expert submission to ACMA on pricing of 700MHz apparatus licences in regional and rural parts of Australia. *Australian Mobile Telecommunications Association, 2013.*

Construction sector competition. Expert advisor on inquiry into building materials markets in New Zealand. *Ministry of Business Innovation and Employment, 2013.*

Telecommunications Regulation. Expert advisor to New Zealand government on design of regulatory arrangements for nation-wide fibre-to-the-premises network. *Ministry of Economic Development and Crown Fibre Holdings, 2009-10.*

Short Course Development and Teaching. Led development and teaching of Covec short courses on "Cost Benefit Analysis", "Competition and Regulatory Economics in Network Industries" and "Regulatory Economics". NZ *Treasury 2012-5 (annually), Government Economics Network 2012, Auckland Council 2012, Electricity Authority 2013, ChCh Council 2013, Commerce Commission 2013, NZ Treasury 2016.*

Dairy Economics & Governance. Expert advisor to team of officials co-ordinated by MAF to investigate competition issues arising from farm gate milk pricing in New Zealand and develop oversight regime for Fonterra's farm gate pricing. *Ministry of Agriculture and Fisheries, 2011-12.*

Damages Dispute. Advised major orchid grower during damages negotiation with Bayer AG which sold a new chemical spray that killed and damaged export orchid crops. *Lingar Orchids, 2010-11*.

Metropolitan Rail Economics: Estimated externalities from metro rail in Auckland and Wellington, developed funding and fare recommendations. *NZTA, 2012-13.*

Telecommunications Policy. Developed principles to guide development of sector-specific competition law in Macao. *DSRT of Macao, 2008.*

Value of Lost Load: Expert economic advisor to London Economics which is contracted to estimate the cost of electricity outages in Texas. *London Economics, 2013.*

Economic impact analysis: Comparison of economic effects of two alternative stadium locations for Auckland. *Auckland Regional Council, 2009*

Electricity Market Reform. Sequence of meetings with Minister of Energy to explore options for significant adjustments to NZ electricity market arrangements.
Ministry of Economic Development, 2006

Electronic Payment Systems: Independent review of commercial and policy issues in electronic payments sector. *Retailers Association, 2012-13.*

Electricity Transmission Pricing: Submission to Electricity Authority on its proposals to change transmission pricing methodology. *Mighty River Power, 2013.*

Telecommunications Regulation. Won international tender to supply and support the first independent regulator of telecommunications in Vanuatu. *AUSAID, 2008-10.*

Competition between Credit Contract Suppliers: Expert testimony in the High Court regarding the impact on competition and consumer welfare of complex fee structures in credit contracts, *New Zealand Commerce Commission, 2012*.

Demand for Fibre Services in Auckland: Report quantifying potential demand for fibre-to-the-home and modelling the business case for investment.
Auckland, Manukau and Waitakere Cities, 2008

Waste Policy. Advising on costs and benefits of alternative methods for reducing waste-to-landfill in the Auckland region.
Auckland Council, 2011-12

Waste Sector Transaction Support: Expert evidence to Commerce Commission in support of Waste Management acquiring several collection businesses in the South Island, *Waste Management, 2009.*

Aviation Merger. Economic modelling to predict the impact of a proposed trans-Tasman alliance between Air New Zealand and Virgin on aviation competition and the New Zealand economy more generally.
Ministry of Transport, 2010-11

Postal Network Access. Economic advice to several postal operators over conditions and pricing of access to New Zealand Post's network. *Freightways Ltd, 2009-16.*

Oil Security: Economic analysis of the social value to New Zealand of holding additional oil stocks and on mechanisms for increasing stocks and the competitive impacts of these.
Ministry of Economic Development, 2004

Broadcast Royalties: Economic analysis of the appropriate royalty payable by radio broadcasters to recording companies pursuant to a reference to the Copyright Tribunal, including econometric modelling of the value to record companies of radio airplay.
Radio Broadcasters Association, 2008-09

Heritage Valuation. Investigating the value to society at large from planning restrictions designed to preserve heritage features in certain Auckland locations. *Auckland City Council, 2008-10.*

Water Development Options. Two reports. One focused on evaluation of alternative (and complementary) options for augmenting supplied of fresh water (including demand management);

the other evaluating network development options for waste water infrastructure. This work was undertaken as part of the "three waters" programme of work. *Watercare Ltd, 2007.*

Electronic Payments. Developed an electronic payments strategy for national grocery retailer faced with significant increases in transaction costs due to industry shifts.
Foodstuffs, 2011

Electricity Network Modelling: Econometric modelling and other advice for new regulatory regime for electricity distribution companies.
NZ Commerce Commission, 2003

Bank Capital Modelling: Jointly commissioned by banks to build econometric model linking the real business cycle to the rate of bank asset impairment.
Westpac, ANZ Bank, ASB Bank, Bank of New Zealand, 2007

Consumer Behaviour – Forex Conversions: Econometric modelling of consumer reactions to extra disclosure of international currency conversion fees on credit card statements.
Bank of New Zealand, 2006

Inflation Forecasting – RBNZ: Comparative study of empirical methods for forecasting inflation.
Reserve Bank of New Zealand, 1995

Tax Policy Econometrics: Sequence of projects, 1992-97. Work included empirical analysis of tax policy and the construction of the first formal revenue forecasting model, which is still in use today.
New Zealand Inland Revenue Department, 1992-7

Publications

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