



COMPETITION
ECONOMISTS
GROUP

Economic Review of TPM Options Working Paper

A REPORT FOR TRANSPOWER

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Executive Summary

1. This report evaluates the Electricity Authority's (EA's) proposed options for revising the transmission pricing methodology (TPM) set out in its Options Working Paper (Options Paper).¹ It reviews and comment from an economic perspective on the analysis and conclusions contained in the Options Paper. It also consider whether there are alternative options worth considering in the second Issues Paper. The views expressed in this report are CEG's and do not necessarily reflect the views of Transpower.

Problem definition

2. The Options Paper raises legitimate questions about the long-term inefficiencies that may arise if the 'wedge' between the benefits that customers receive from transmission investments and the charges they pay grows over time. In *principle*, the greater this disparity becomes, the more likely it is that:
 - customers will make sub-optimal investment decisions that impact adversely upon Transpower's investment costs, harming dynamic efficiency; and
 - parties will alter their grid usage in undesirable ways to avoid those outlays, reducing static efficiency.
3. Although this potential shortcoming is worth exploring in the second Issues Paper, many of the other problems identified with the current TPM are either mischaracterised or overstated in the Options Paper. For example, despite to the suggestions to the contrary:
 - the TPM *has* sent appropriate price signals to market participants in the past and, through Transpower's Operational Review, it is adapting to send more efficient signals given recent changes in circumstances;
 - the TPM is cost-reflective from an economic perspective, since all grid users face prices that are greater than the short run marginal cost (SRMC) of that usage and less than the 'stand-alone' cost of supplying each customer;
 - there is no evidence to suggest that the Commerce Commission's (Commission's) new investment process has produced inefficient outcomes in the past, and no reason to think that the TPM reforms in the Options Paper would produce superior results in the future; and

¹ Electricity Authority, *Transmission Pricing Methodology Review: TPM options working paper*, June 2015 (hereafter: "Options Paper").

- there is ample scope to address issues through incremental reform of the current guidelines, which suggests that the TPM is durable, irrespective of the ongoing controversy, which would persist under *any* option.
4. The analogy that has been repeatedly used to describe the problems with the TPM is also unhelpful. The TPM is said to be comparable to a group splitting a restaurant bill equally, even though some have ordered more than others.² It is not. The service that Transpower provides to its customers and the manner in which it charges them bear no resemblance to a restaurant.
 5. Nevertheless, the Options Paper does establish that there is at least the *possibility* that the existing TPM could be reformed so as to be more efficient – or at least ‘fairer’.³ Below, we explore the extent to which the alternative pricing options that have been proposed are likely to achieve these objectives.

Overarching problems

6. There are a number of overarching problems that affect all of the proposed pricing options to some degree. These shortcomings limit the extent to which they can address the potential inefficiencies that have been identified with the current TPM, and they may create *new* problems. These deficiencies are as follows:
 - the application of key concepts such as ‘beneficiaries’ and ‘market-like’ is inconsistent, and there are a number of contradictions between:
 - the problems that has been defined (whether valid or not) and the reform options that have been proposed, e.g., many of the charges exhibit an inefficient time profile of charges;
 - the approaches taken from charge to charge, e.g., deeper connection charges are allocated to generators based on their anytime maximum injection (AMI), whereas Area of Benefit (AoB) charges are allocated based on MWh; and
 - the approaches taken within the same charge, e.g., AoB and residual charges are allocated to electricity distribution businesses (EDBs) and

² Weir., J, ‘Power bills could rise in Auckland, Northland under “option”’, (sourced 10 July 2015): see: <http://www.stuff.co.nz/business/money/69425610/power-bills-could-rise-in-auckland-northland-under-option>.

³ The Options Paper raises reasonable doubts about the potential *inequity* of the current allocation of sunk costs. Although it is not couched explicitly in these terms, the implication is that because Transpower’s recent investments have primarily benefited the North Island it is consequently *fair* for customers in that region to pay more, and for customers in the South Island who have not benefited as much to pay less. That view is not necessarily unjustified.

major industrial customers using different approaches, without a sound efficiency justification.

- the proposed sequencing of the charges is unworkable, i.e., it is not feasible to prioritise the deeper connection charge over the AoB charge, since:
 - it cannot be applied *ex ante* to assets not yet built since the *actual* load flow data would not be available – it would instead be necessary to use forecasts, which would create insuperable problems;
 - assets may transition in and out of the deeper connection charging framework over time, leading to highly volatile charges and compromising parties' ability to engage constructively in new investment processes; and
 - there would be no satisfactory way to reapply AoB charges to a narrower group of assets if certain assets within a broader asset group (such as the NIGU lines or the Wairakei Ring) are reclassified as deeper connection;
- insufficient attention is given to practical factors such as economies of scale that will have influenced investment outcomes,⁴ which is problematic since:
 - the assets to which deeper connection and AoB charges are applied may be larger and more expensive than those that parties would have opted for if given the choice (see further discussion below); and
 - allocating 100% of the costs of those assets to the identified parties may cause them to lobby for smaller, less efficient investments and/or to change their behaviour in undesirable ways to reduce their charges;
- if implemented, the proposed options would result in an exceedingly complex TPM, which raises questions about:
 - whether Transpower can design, implement and administer the methodology in a cost effective manner; and
 - whether parties will be able to fully understand the methodology in order to engage constructively in new investment processes;
- the options would expose generators to significantly more transmission charges, which may deliver few (if any) efficiency benefits, but may result in significant static efficiency costs.

7. These shortcomings mean that the options lack cohesion. They also contain many arbitrary assumptions that have a large impact upon the allocation of charges. For these reasons alone, they should not be countenanced as currently designed. There are also more specific problems with the individual charges, which we set out below.

⁴ Once the land has been purchased and the towers built, there is not much difference in cost between a low and a high capacity line. For these reasons, rather than building an asset sized to meet the near-term needs of existing users, it will usually be more efficient to build a larger link, sized to handle demand that may not emerge until some later point – potentially from other parties.

Note that we have not reviewed the proposed loss and constraint excess (LCE) and static reactive (kvar) charges in this report.

Deep connection charge

8. The deeper connection charge is described in the Options Paper as ‘market-like’. This characterisation is predicated on the belief that the framework will capture situations in which, in the absence of a regulator, the parties upon whom the charges are levied would have:
 - come together to negotiate an efficient commercial agreement to build the deeper connection assets in question; and
 - faced the same net cost as they are being exposed to via the deeper connection charge (at least, that is the implication of the methodology).
9. Neither of these assumptions is correct. The application and level of the deeper connection charge may bear no resemblance to a plausible (hypothetical) competitive market outcome, because:
 - the charge will *not* capture all situations in which a hypothetical commercial negotiation would have been possible in the absence of a regulator, since:
 - in truth, this may be an empty set – in the absence of a regulator and an investment framework, these assets may not have been built at all;⁵ and
 - in any event, the application of the charge is arbitrary, i.e., there will often be no good reason why it is applied in one scenario but not in another;⁶
 - in most (if not all) cases, the parties upon which the charges are levied would be facing a *lower* net cost in a hypothetical market setting, since:
 - they might have built something smaller and less expensive to meet just their own needs, i.e., without spare capacity;
 - if they did build an asset with surplus capacity, they would *sell* it to other users to reduce their net costs, i.e., there would be no ‘free riding’;⁷ and

⁵ The thought experiment being conducted in the Options Paper rests on a false premise. The presence of a regulator does not *prevent* market-based investments from occurring. Rather, it allows investments to occur that otherwise *would not happen* because of the economic characteristics of transmission. This is particularly the case for reliability investments in the core grid (many of the investments earmarked for deeper connection charges fall into this category), See: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013; and Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, section 2.2.

⁶ For example, there is no reasonable basis to conclude that a generator with, say, a 75% share of load flows across a node would be able reach a commercial agreement with a handful of smaller generators, but that three, say, equally sized generators (with a 33.3% share of load flows) would not. Nevertheless, a deeper connection charge will be applied in the former scenario, but not the latter.

- there would be unlikely to be a large discrepancies between the extent to which a party uses an asset and the net cost they faced in doing so.⁸
10. Seeking to recover 100% of the costs of deeper connection assets from the identified set of users (who may only be a small sub-set of *all* users) may consequently risk giving rise to the dynamic and static inefficiencies described above. The charge may also result in undesirable price volatility as customers connect and disconnect. Averaging the HHI calculation over five years may cause further problems:
 - there may be periods when newly connected generators are not paying the charges, but others are, which could distort competition; and
 - generators may time their entries so as to minimise exposure to deeper connection charges, which may cause cheaper generation to be delayed.
 11. Finally, the rationale provided in the Options Paper for specifically excluding the HVDC link from the deeper connection charge is unsound.⁹ The problems described above suggest that the more appropriate course of action is to not apply the charge *to any assets* – at least not as it is currently designed.

Area of benefit charge

12. 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, since:
 - when generators formulate wholesale bids, they will factor in the AoB charges they expect to pay;
 - these are not ‘true’ short-run marginal costs – they are *fixed sunk costs* that have been *made* variable by the AoB charge; and

⁷ There are a number of ways in which parties may end up using deeper connection assets, but not paying deeper connection charges. For example, if the supply-side HHI is met and the demand-side HHI is not (but is still positive), then generators would be paying deep connection charges, but not load. That would not happen in a hypothetical commercial setting.

⁸ Under the charging framework, a party may account for only a modest percentage of load flows, yet be allocated a much larger percentage of an asset’s total costs because of the use of AMI as an allocator (and vice versa). The ‘Clyde to Roxburgh’ link described in the EA’s TPM Options Paper workshops is illustrative. See: Electricity Authority, *Transmission Pricing Methodology (TPM) Review, TPM options working paper, Workshops, July 2015*, slide 18.

⁹ There is no meaningful distinction between the physical characteristics of the HVDC link and many of the other assets earmarked for deep connection charges, such as the NIGU and NAaN lines that would warrant differential treatment. Neither of these upgrades is ‘required’ to connect a party to the grid – they are, after all, expanding a network that already exists.

- this may lead to generators being dispatched out of ‘true’ merit order (i.e., based on their ‘true’ SRMCs), resulting in inefficiently higher prices.
13. The periodic assessment of beneficiaries is also likely to cause ongoing and escalated disputation and controversy, i.e., the very outcomes that the proposed pricing options are ostensibly trying to avoid. It may also cause parties to change their conduct in undesirable ways in order to appear ‘less of a beneficiary’.

LRMC charge

14. The biggest potential problem with a long run marginal cost (LRMC) charge in the present context is that, because LRMC oscillates through time, so too do the benefits that any such price signal can feasibly deliver.¹⁰ In this particular instance:
- Transpower has just finished a large ‘wave’ of upgrades, and new major investment is not going to be needed for many years; and
 - this means that the benefit of pushing back those future investments is currently very small in net present value terms, as indicated by the low level of the LRMC charge estimated in the Options Paper.¹¹
15. For that reason, although we agree that LRMC price signals can promote dynamic efficiency *in principle*, we do not consider that there would be material benefits in *this instance*, given the point in the investment cycle.¹²

SPD charge

16. 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.¹³ Generators might seek to optimise the trade-off between:¹⁴

¹⁰ CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §63.

¹¹ See: Options Paper, Figure 1.

¹² We note also that the RCPD charge is already capable of providing a signal to users to reduce peak usage when a region becomes susceptible to congestion, so it is unclear what additional value an LRMC charge would add. This will no doubt be reflected in the quantitative CBA in its second Issues Paper.

¹³ Although, as the EA and Transpower have recognised, the HAMI charge does sometimes result in certain generating units ramping down their output in order to avoid contributing to their HAMI.

¹⁴ CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §87.

- lowering transmission charges by bidding above SRMC so as to appear 'less of a beneficiary' in the SPD modelling; and
 - the consequent increase in the probability of not being dispatched, with the attendant negative effects on profitability.
17. This conduct could compromise the efficiency of the wholesale market . The charge will also make generators' cash-flows less certain,¹⁵ which may result in additional risk premiums being incorporate in wholesale (and, in turn, retail) prices. The cost of disputes would also be likely to increase, since parties can be expected to continually agitate for modelling inputs to be changed in ways that favour them.¹⁶

Residual charge

18. The Options Paper states that the residual charge should be designed so as to limit distortion in the use of the grid resulting from its imposition. The proposal is to apply a flat, postage stamp capacity charge on load. However, this is allocated differently as between EDBs and major direct-connect customers:
- for EDBs, the intention is to levy the charge based on the sum of the nominal capacities of the active ICPs in their network areas;¹⁷ and
 - for direct-connect customers, the proposal is to levy the charge based on their respective anytime maximum demands (AMDs).
19. The net effect of this inconsistent treatment is that the overwhelming majority – more than 97%¹⁸ – of the residual charge is allocated to EDBs. In our opinion, a robust rationale has not been provided for the application of different charging parameters (and the attendant redistribution), because:
- although the capacity of some direct connect customers' connections substantially exceeds their AMD – this is also likely to be true of many EDBs, and so it does not provide a sound rationale for the distinction;
 - although EDBs may have an incentive to inefficiently suppress load to avoid an AMD-based charge, this could be avoided by retaining an RCPD charge which is measured over a large number of periods, e.g., 100+; and

¹⁵ CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 5.1.

¹⁶ See for example: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 3; CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.

¹⁷ Options Paper, §6.102.

¹⁸ EDBs estimated total installed capacity is 47,044MW and major industrial's cumulative AMD is only 1,252MW, and so EDBs are allocated 97.4% of the 48,297MW total capacity ($47,044 \div [47,044 + 1,252]$).

- EDBs may also seek to inefficiently reconfigure their assets so as to limit their exposure to the charge, e.g., by constructing micro-grids so as to reduce their numbers of ICPs.

20. In contrast, 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.

Applications A and B

21. The choice between Applications A and B primarily boils down to the potentially competing impacts upon dynamic and static efficiency from changing the way that the sunk costs of existing assets are recovered:

- changing the TPM cannot affect the efficiency of investments that have already been made – it can only effect new investments that are made in the future, which might steer one towards Application B; but
- Application B might result in a growing disparity between the charges parties pay and the benefits they obtain which, as we set out above, might affect investment over the long-term and steer one towards Application A.

22. The biggest problem with Application A is its potential to disrupt grid usage decisions over the near- to medium term. As we explained above, all of the proposed charges entail these risks. This creates a potential dilemma:

- on the one hand, the Options Paper appears to suggest that Application B would not result in *enough* rebalancing, i.e., the ‘wedge’ between ‘prices and benefits’ would remain too great; but
- on the other hand, the implication seems to be that there may be *too much* rebalancing under Application A, i.e., the magnitude of the price changes may cause parties to change their behaviour in inefficient ways.

23. The proposed transition mechanisms appear to be an attempt to reach a ‘middle ground’, i.e., to facilitate a reallocation of charges, but to soften the impact of price changes. The trouble is that neither capping the rate of change nor the prices applied to EDBs will prevent efficiency from being impaired. For example:

- if a party knows that it will be paying, say, 10% more in five years’ time it may simply change its behaviour now to avoid that future increase, notwithstanding the fact that the transition to that new level may be ‘smoothed’; or
- the party may simply change its behaviour in the future (e.g., after a few years) – the chief benefit of the transition mechanism in this instance would be that it delays that inefficient conduct; but it does not *avoid* it.

24. It follows that 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.

Implications and alternative options

25. There may be alternative reform options available that go some way to addressing the overarching potential problem the EA has identified with the TPM, but that do not entail quite the same drawbacks. Specifically, there may be other methodologies on offer that:
- result in *some* rebalancing of the sunk costs of past investments (including the \$2b of recent investments), but with more modest wealth transfers than those associated with Application A (and thus potentially fewer distortions);
 - provide more efficient price signals to consumers – including over time, i.e., signals that provide a clear indication to customers of the cost their choices impose on the transmission network;
 - do not give rise to the intertemporal problems that would be caused by the ‘sequencing’ of the deeper connection and AoB charges under the approaches proposed in the Options Paper;
 - provide positive incentives for customers – including those that have not actively engaged to date – to monitor transmission expenditure without simply aggravating unproductive price-shock motivated opposition; and
 - are more easily understood by all interested parties and more straightforward for Transpower to implement and operate – all of which will result in fewer transaction costs across the sector.
26. There are at least three alternatives that may be worth considering. The first is a simplified version of the ‘base’ option. Using the existing base option as a starting point, a more straightforward approach might be to:
- retain a modified version of the AoB charge in which a more efficient time profile of charges is applied;¹⁹
 - remove the deeper connection charge; and
 - retain the existing RCPD-based residual charge.

¹⁹ This could be achieved by applying annuity-style depreciation or by applying an average depreciation rate to non-depreciated asset values

27. A second option would be to seek to justify the reallocation of the costs of *just* the HVDC link – the charge that has proved to be more controversial than any other. Some of the potential allocation options include the following:
- using an up-to-date estimation of the array of ‘private benefits’, such as that undertaken by the EA in its first issues paper and summarised in Table 6 of its Options Paper (the allocations for Pole 2 and Pole 3); or
 - reapplying the 53:47 split that applied from 1993 to 1996, i.e., 53% to North Island load and 47% to South Island generators (noting that this allocation related to Pole 1 and Pole 2 – not Pole 2 and Pole 3); or
 - a simple 50:50 split between South Island generators and North Island load – or even a 50:50 split between South Island generators and *all* load (since South Island consumers may also derive significant private benefits); or
 - using an allocation of the share of flows across the link, i.e., based on the application of the EA’s load flow modelling approach (but perhaps without the attendant application of the HHIs).
28. A third option would be to apply customised interconnection rates to off-take customers located in different areas. There are various ways in which these customised rates might be applied, for example:²⁰
- a simple ‘two island rate’ could be applied, whereby off-take customers in the North Island paid a higher rate than customers located in the South Island; or
 - charges could be applied to each of Transpower’s existing interconnection regions – the LSI, USI, LNI and UNI – a ‘four rates’ option; or
 - there could be more graduated rates, e.g., with the interconnection rate increasing as one moved further north, or in bespoke locations.²¹
29. In our opinion, each of these alternatives has the potential to advance some or all of the objectives set out above. However, as we explain in detail in the body of this report, they also each have distinct disadvantages. For example:
- because the ‘simplified base option’ continues to incorporate the AoB charge, all of the potential drawbacks with that charge that we described above would continue to apply; and

²⁰ One means of customising the interconnection rates is to allocate Transpower’s revenue requirement amongst regions based on the non-depreciated replacement cost of its interconnection assets in those respective locations.

²¹ These options were explored in depth by the CEO forum in 2009, see: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, section 5.1.

- because the two other options entail the identification and allocation of transmission costs to perceived beneficiaries, they involve the same challenges that we described above in these respects.
30. To be clear, we are neither endorsing these options, nor suggesting that they would necessarily deliver net benefits. Those are ultimately empirical matters. Rather, we simply propose that there may be merit in including these methodologies in the second Issues Paper.

1 Introduction

31. This report has been prepared by CEG on behalf of Transpower. Its purpose is to assist Transpower as it evaluates the Electricity Authority's (EA's) proposed options for revising the transmission pricing methodology (TPM) set out in its Options Working Paper (Options Paper). We have been asked to:
 - review and comment from an economic perspective on the analysis and conclusions contained in the Options Paper so as to assist Transpower's submission; and
 - consider whether there are any alternative options that might better meet the EA's objectives that it might consider including in its second Issues Paper.
32. We do so in the remainder of this report, which is structured as follows:
 - **section two** examines the updated views on problems with the current TPM – the so-called 'problem definition';
 - **section three** provides some general observations on the proposed options, including problems common to all of those alternatives;
 - **sections four to six** consider the specific merits of the various pricing approaches; namely:
 - **section four** examines the deeper connection charge;
 - **section five** evaluates the area of benefit (AoB) charge;
 - **section six** reviews the SPD, LRMC and residual charges; and
 - **section seven** considers the respective merits of Applications 'A' and 'B' and proposes an alternative approach;
 - **section eight** sets out the implications of analysis in sections two to seven for the proposed options and suggests some alternative approaches; and
 - **Appendix A** provides a list of previous papers that we have drawn upon extensively throughout this report.
33. Note that we have not reviewed the proposed loss and constraint excess (LCE) and static reactive (kvar) charges in this report. Finally, we stress that the opinions expressed throughout this report are our own and do not necessarily reflect the views of Transpower.

2 Problem Definition

34. The Options Paper provides a revised view of the problems with the current TPM. Those problems are said to broadly sit within four categories. Specifically, the Options Paper states that the TPM:²²
- is not adaptive and sends the wrong price signals;
 - does not appear to be cost-reflective;
 - fails to support the discovery of efficient transmission investment through the transmission investment approval process; and
 - may not be durable.
35. In our view, although the extent of the problems with the current TPM is often overstated, the Options Paper nonetheless establishes that there is *potential* for the methodology to be more efficient – or at least ‘fairer’. We elaborate below.

2.1 Adaptability and price signals

36. The Options Paper states that the current TPM has not adapted well to recent transmission investment. This is said to result in dynamic and static inefficiencies. We consider the supposed sources of these inefficiencies below, before examining the adaptability of the existing TPM to changing circumstances.

2.1.1 Forward-looking price signals and dynamic efficiency

37. The Options Paper highlights the changes (or lack thereof) in transmission prices before and after investments. These changes are claimed to compromise dynamic efficiency. This is said to be illustrated by the increase in the strength of the HVDC and interconnection charge pricing signals *following* the substantial recent investments. The Options Paper explains that:²³

*‘From a (**dynamic**) efficiency perspective the pricing signal should strengthen **before the investment is made**. If the pricing signal does not strengthen before an investment, users will continue to use the transmission network even when it is congested, bringing forward the need for transmission investment.’ [Emphasis added]*

38. We agree with this basic proposition. As CEG has explained in several of our previous reports, the only way to deliver dynamic efficiency benefits through a

²² Options Paper, §4.2.

²³ Options Paper, §4.6.

pricing framework is by signalling to users the forward-looking costs of future investment needs *before* those investments are made.²⁴ However, the current interconnection charge *did* provide such a signal.

39. Prior to Transpower's recent major investment programme, the regions that were most susceptible to congestion were the UNI and USI. Because the average RCPD has been calculated over 12 period demand periods in these regions it provided off-take customers with an incentive to shift load to non-peak times so as to minimise their annual interconnection charge;²⁵ specifically:
 - if an off-take customer did not reduce its contribution to the 12 peak demand periods, and other customers did, then it would pay a larger annual interconnection charge; whereas
 - in the LNI and LSI regions that have been less prone to congestion, the average RCPD is measured over 100 peak demand periods, and there is not the same incentive to reduce load, i.e., it is much harder to control 100 peaks.
40. In other words, the current interconnection charging arrangements have reflected a trade-off between recovering the costs associated with the sunk shared grid infrastructure in the most efficient way possible, while:
 - minimising distortions to consumption in the LNI/LSI regions; and
 - providing an incentive to off-take customers in the UNI/USI regions – the regions that have been susceptible to congestion – to reduce demand during peak times to improve the efficiency of usage decisions and investment outcomes in the longer-term.
41. Now that Transpower has completed its major investment programme in the UNI and demand growth has slowed there are fewer benefits to be obtained from providing this incentive to customers in these regions. Instead, the optimal price signal may instead be to *encourage use of these assets*. As we explain in the following section, it is for this reason that Transpower recommended recently to (amongst other things) increase the number of peak demand periods for the RCPD charge to 100 in the UNI and USI – a proposal the EA has since accepted.²⁶

²⁴ Our report in response to the EA's CBA working paper addressed this topic extensively – see in particular: CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, sections 2, 3 and 4. At §78 we concluded that: 'While we do not agree that modifications to the TPM can deliver material static efficiency benefits, we accept that, in principle, dynamic efficiency benefits might be achievable.'

²⁵ As we explain below, Transpower recently proposed to increase the number of measurement periods in these regions to 100 reflecting the fact that, now that these investments are in place and demand growth has slowed, it is no longer desirable to shift/suppress demand. The EA has since accepted this proposal.

²⁶ Electricity Authority, *Transpower's proposed variation to the Transmission Pricing Methodology (four components) Decisions and reasons*, 4 August 2015.

42. This reflects a point that we have made in several of our previous reports.²⁷ Namely, there tends to be very little (if any) benefit in providing a forward-looking price signal *after* major investments have been made, or substantially altering the manner in which those sunk costs are recovered. This is because:
- increasing prices to the perceived beneficiaries or causers of an investment (to the extent they can be identified) *after* it has been sunk risks prompting them to reduce their consumption – potentially stranding the assets;²⁸ and
 - there may be little point in providing a strong signal of the cost of *future* investments because, if they are not expected to take place for many years, the optimal signal would be weak so as to encourage use of the new capacity.
43. It follows that, in the current circumstances:
- any change in the allocation of the charges for *existing* assets (including the \$2 billion investments already sunk) has the potential to inefficiently compromise grid usage (static efficiency);²⁹ and
 - the potential benefits from altering *future* investment outcomes (i.e., deferring future costs³⁰) through *forward-looking* price signals are likely to be relatively modest in present value terms, given that there are no large investments planned for the near future (dynamic efficiency).
44. The confluence of these factors reduces substantially the dynamic efficiency benefits that can be obtained from retaining the current RCPD charge in the UNI and USI or providing *some other* form of forward-looking price signal (such as the proposed LRMC charge – see section 6.1). The EA seeks to address this problem in its *Questions and answers on the TPM options paper* by stating that:

²⁷ CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §76-92.

²⁸ It is for this reason that price signals must be provided in advance of such investments. If the LRMC of an expansion is signalled to users, and they continue to use the asset (or increase their usage), this indicates that they are willing to pay for it (presumably because they will derive sufficient private benefits). If they reduce their consumption and the investment is consequently no longer needed, this illustrates that they were not willing to pay for the new investment (because they will not derive sufficient private benefits). The latter is an efficient outcome, since it avoids the capital cost of a new investment from which consumers would not sufficiently benefit *before* it is sunk.

²⁹ We have explained this point in detail in many of our previous reports. See: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 4; CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, section 4.1; and CEG *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.

³⁰ For example, the costs saved by deferring by 5 years an investment that would otherwise be made in 50 years will be much lower in present value terms than deferring an investment that would otherwise be needed tomorrow. We explained this in detail in our response to the EA's CBA Working Paper. See in particular: *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §89.

‘While there are no large transmission investments planned in the near future, there are in the longer term. Now is the perfect time for getting a charging regime in place that will help to ensure this investment is efficient. Further, as we have seen in the past, transmission investment plans can change quickly as market circumstances change, so it is important that an efficient charging regime is in place if it does.’

45. We agree that, in principle, there may be merit in making pre-emptive changes to the TPM in anticipation of future investments. However, it is questionable whether now is the best time to attempt to do so. There are a number of factors that suggest that there might be a ‘positive option value’ from waiting before seeking to implement a forward-looking price signal. For example:
 - from a practical perspective, as the next major round of investment draws closer, it seems likely that there will be at least some review of the TPM at that point – irrespective of whether changes are made in the near-term;
 - as noted above, the existing RCPD charge already has the capacity to provide a signal to users to reduce peak usage when a region becomes susceptible to congestion, i.e., Transpower could simply reduce the number of peaks; and
 - as we explain below, Transpower has illustrated that the TPM can be adapted relatively quickly through an Operational Review when inefficiencies become apparent – this vehicle could therefore be used again in the future now that precedent and process has been established.
46. For those reasons, while we concur with the Options Paper’s assessment that forward-looking price signals can promote dynamic efficiency, we do *not* agree that:
 - the TPM has not provided such signals in the past – it has, through the RCPD charge (and, as we explain below, it has been changed through the operational review so as to continue to provide efficient signals into the future); and
 - there are material dynamic efficiency gains to be obtained from providing additional forward-looking price signals or reallocating the approved economic costs of recent investments in these particular circumstances.
47. As we explain further in section 6.1, the very limited potential for dynamic efficiency gains is illustrated by the very small LRMC charge displayed in Figure 1 of the Options Paper. The magnitude of this charge is unsurprising. Given the point in the investment cycle, the optimal price signal is to encourage use of the new capacity. This will necessarily affect the quantitative CBA in its second Issues Paper.

2.1.2 Static efficiency and adaptability

48. The Options Paper suggests that a consequence of the charging framework within the current TPM is that prices are sometimes too high *after* an investment has been made and the costs are sunk. Specifically, it states that:³¹

*'The strengthening of the signal after the investment is made, as has occurred, sends a **statically inefficient** price signal to not use a new asset even though spare transmission capacity is at its highest.'* [Emphasis added]

49. Depending upon the way that transmission charges are designed to recover the costs of existing assets, it is certainly possible that inefficient reductions in demand could lead to deadweight losses. In this respect, there does appear to be an element of static inefficiency associated with the current TPM; namely:

- we have highlighted in our previous reports the HAMI-based HVDC charge does lead to South Island generators occasionally inefficiently withholding capacity during times of peak demand in order to avoid attracting additional HVDC costs;³²
- in general terms, the RCPD-based interconnection charge may be causing grid users in the UNI and USI to inefficiently reduce their consumptions at times of peak demand – something that is arguably now not desirable, given the spare transmission capacity that exists following the recent upgrades in the UNI and the slowdown in demand growth; and
- more specifically, the RCPD allocation can cause inefficient demand response in the summer months, including at the NZAS smelter, which might be discouraged from shifting its production to take advantage of this period of below-average wholesale prices due to the higher transmission costs it would consequently face;³³

50. However, Transpower has recognised the potential problems with these charges and has sought to mitigate them through its Operational Review. Moreover, the potential solutions will not necessarily require widespread reform. Transpower has recommended that the chief static inefficiencies be addressed by:

- calculating the RCPD allocation based on 100 regional peaks per year, rather than the current 12, for the UNI and USI regions;

³¹ Options Paper, §4.7.

³² See for example: CEG Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower, March 2014, §54. We also explore this issue in more depth in section 8.3.

³³ Electricity Authority, *Transpower's proposed variation to the Transmission Pricing Methodology Consultation Paper*, 21 April 2015, p.16

- excluding summer trading periods from the capacity measurement period used to calculate a customer's RCPD in all four RCPD regions; and
 - changing the HAMI parameter to an average MWh charge;
51. At the time of writing, the EA had accepted the first two recommendations (albeit with some minor adjustments³⁴), but had yet to make a decision on the third. In other words, although the Options Paper identifies material static inefficiencies within the existing TPM, there is a high probability that those problems will fall away very soon without the need for extensive reform. This clearly has material implications for the problem definition.
52. Plainly, these developments are inconsistent with the contention that the TPM is not adaptive and sends the wrong price signals. Rather, they indicate that the TPM *can* send appropriate price signals and can adapt – and relatively quickly – when circumstances change (we note that the operational review spanned just one year). In our opinion, the RCPD charging arrangement is a particularly good example of these adaptive properties:
- as noted above, prior to the recent upgrades, the RCPD charge was sending an appropriate signal to customers in the UNI and USI to reduce/shift demand during regional coincident peaks;
 - now that investments have occurred in the UNI region and demand growth has slowed, Transpower has undertaken review that will see that peak signal substantially reduced in these regions so as to appropriately encourage use; and
 - if any region becomes congestion prone in the future, Transpower could then undertake a similar review and ‘reactivate’ the peak price signal by reducing the number of measurement periods in the affected areas.
53. We observe also that the recently concluded Operational Review was the first of its kind. It was therefore something of a ‘voyage of discovery’ for all participants, who were unfamiliar with the process. With the benefit of that experience, it is reasonable to expect that subsequent reviews will run even more smoothly and precipitate efficiency-enhancing reforms more swiftly.
54. Finally, we note that although the Options Paper is correct to note that static and dynamic efficiency require price signals to strengthen *before* an investment is made,³⁵ this is not reflected in the design of its many of the options. As we explain in

³⁴ Namely, the EA decided to exclude the summer trading period from the LSI, LNI and UNI regions, but not the USI. See: Electricity Authority, *Transpower’s proposed variation to the Transmission Pricing Methodology (four components) Decisions and reasons*, 4 August 2015.

³⁵ Noting that, for the reasons we set out above, there is arguably little near- to medium-term benefit from providing such a signal in the *current* circumstances, given the point in time in the investment cycle.

detail in section 3.1, with the exception of the LRMC charge,³⁶ none of the other options would provide a price signal to users before an investment is made. They would all do so *afterwards*, and in an inefficient way.³⁷

2.2 Cost reflectivity

55. The Options Paper expresses concerns about the degree to which the current TPM is ‘cost-reflective’, and the extent to which that may change over time as new investments are made. It states that prices are cost-reflective and signal the economic costs of service provision when they are:
 - subsidy free (equal to or greater than incremental costs, and less than or equal to stand-alone costs);
 - have regard, to the extent practicable, to the level of service capacity; and
 - signal, to the extent practicable, the impact of additional usage on future investment costs.
56. The basic concern appears to be that there are customers currently paying for transmission assets from which they derive relatively little benefit. In a similar vein, there are other customers who are said to be the principal beneficiaries of investments who are thought to be paying too little.

2.2.1 The TPM is cost-reflective

57. The chief concern in relation to ‘cost reflectivity’ appears to be that there are currently customers who are paying for investments that are being used to deliver services largely to other customers. Those customers who benefit from or caused investments to occur are therefore said to be not paying the ‘full cost’ of those investments. This has been likened this to a group splitting a restaurant bill equally, even though some have ordered more than others. EA Chairman Dr Brent Layton has stated that:³⁸

³⁶ And setting aside the LCE and static reactive charges, which we do not explore in this report.

³⁷ The only way in which the implications of new investments would be signalled to customers *beforehand* is through the new investment process – as is currently the case. We acknowledge that the Options Paper states that the proposed reforms will give rise to a more efficient investment approval process by providing greater incentives to perceived beneficiaries to engage constructively. However, as we explain in section 2.3, in our view, there is good reason to think that the options would not have a positive impact upon those processes, and on the investments ultimately made.

³⁸ Weir., J, ‘Power bills could rise in Auckland, Northland under “option”’, (sourced 10 July 2015): *see*: <http://www.stuff.co.nz/business/money/69425610/power-bills-could-rise-in-auckland-northland-under-option>.

‘That would probably work well when everyone is consuming about the same ... but when the bill has gone up sharply and some people were eating and drinking a lot more than others, the picture changed.’

58. Whilst intuitively appealing, this analogy does not assist in elucidating the underlying economic concepts. In fact, it has the potential to confuse those matters. The service that Transpower provides to its customers and the manner in which it charges them bears no resemblance to a restaurant (or a potato farm³⁹ or a business managing a fleet of Toyota Corollas⁴⁰ – similarly false analogies that have featured in earlier papers). For example:
- a restaurant will incur a much higher proportion of variable costs preparing and delivering food to its customers (e.g., the costs of fresh ingredients, labour, rent, etc.), whereas Transpower’s costs are mostly fixed and sunk;⁴¹
 - restaurant customers will typically pick items off a menu *a la carte* but Transpower’s customers share an interconnected grid – in this sense, they are all receiving the same regulated service to some extent;⁴²
 - restaurant customers receive a bill that reflects the range of choices that they have ordered, but Transpower cannot always do this because electricity is a fungible product; and
 - restaurants face competition from other dining establishments, but Transpower is a natural monopoly provider of transmission services – which limits substantially the extent to which customers can switch to alternatives.
59. Nonetheless, for the sake of illustration, let us retain the analogy – but adapt it to better fit Transpower’s actual circumstances. What would Transpower’s ‘restaurant’ look like in this hypothetical setting? It would be a very unusual establishment indeed. For example:
- it would purchase in bulk all the food that it needed to serve for a prolonged period and it would be unable to sell any surplus stock, i.e., that upfront purchase cost would be fixed and sunk;

³⁹ Electricity Authority, *Transmission Pricing Methodology: issues and proposal, Consultation Paper*, 10 October 2012, §5.6.74.

⁴⁰ Electricity Authority, *Transmission Pricing Methodology: Connection charges, Working Paper*, 13 May 2014, §7.44.

⁴¹ As we set out in more detail below, the short run marginal cost (SRMC) of using the interconnected grid is equal to the cost of transmission losses and constraints (reflected in nodal price differentials).

⁴² There are clearly exceptions to this, such as connection assets. However, Dr Layton is referring principally to investments in the interconnected grid, e.g., the NIGU and NAaN lines, etc.

- it would serve that food around the clock in a ‘buffet-style’, i.e., even though the diners might be eating different things and in different amounts, they would all be partaking in the same smorgasbord that was always available;
 - it would know the *total* amount each diner consumed but it would have only some idea about *what* they had eaten, i.e., it would know that a diner had eaten, say, 500g of food, but it may not know what comprised that quantity;⁴³
 - it would know that it had the only kitchen in town and would therefore have a very good idea of the maximum price it could charge its customers without causing them to ‘build their own kitchens’ or simply go hungry; and
 - it would want to recover the costs that it had incurred without discouraging anyone from eating, since if some customers chose not to dine, this would raise the price for everyone else, i.e., it would be in everyone’s interest for all to eat.
60. How might the restaurant set its prices in these circumstances, given the limited information? One option would be to charge a flat price per customer (or plate), i.e., a price equal to its total costs divided by the number of customers. Another would be to set a fixed price ‘per kilogram’ – irrespective of what foodstuffs made up that weight. To be sure, neither approach necessarily seems ‘fair’, since:
- under the first approach, the ‘light eaters’ might legitimately complain that they did not eat as much as others; and
 - under the second approach, a diner who ate only rice might ask why he is paying the same as someone who partook in the lobster (remembering that, at this peculiar restaurant, the owner does not know exactly who ate what).
61. However, that does not mean that the prices that would be produced by application of either methodology would not be ‘cost reflective’ or that they would be *inefficient* from an objective, economic perspective. It is important to recognise that:
- the prices would exceed the short-run marginal cost (SRMC) to the restaurant of serving each customer, e.g., the cost of washing and supplying plates, cutlery, tables, etc.; and
 - the prices may still be less than the amount that all diners (including the lighter eaters) would be willing to pay – especially given that it has the only kitchen in town, i.e., it is likely to be less than the stand-alone cost.
62. From an economic perspective, in the presence of significant fixed, sunk costs, all that matters is whether prices are subsidy-free, i.e., between incremental costs and stand-alone costs. The hypothetical restaurant’s prices *meet this criterion*.

⁴³ In much the same way that Transpower can see how much a customer has injected/withdrawn from the grid, but cannot necessarily identify all of the transmission assets that it has ‘benefitted from’ or ‘caused’ to be there.

Switching back to the ‘real world’, it is clear that the TPM *also* complies with this basic economic principle.

63. The short-run incremental cost of transmission is equal to the cost of losses and any constraints.⁴⁴ These short-run costs are reflected in the differences in wholesale spot prices between nodes. In other words, all transmission grid users pay a price that is at least equal to the short-run incremental cost of supply.
64. The remaining fixed costs of the existing transmission assets are recovered through a series of fixed charges. It is safe to presume that none of these fixed charges exceed the stand-alone cost of supplying transmission services to any particular customer. This is because if the transmission charge levied upon a particular customer *did* exceed that level then it would rationally disconnect from the grid – and stand alone, as it were. The existing TPM is consequently *subsidy-free*.
65. The Options Paper is also correct to state that, in *principle*, an efficient, cost-reflective TPM would signal the impact of additional usage on future investment costs. However, for the reasons we set out in the previous section, in the current circumstances there may be little practical benefit in doing so, because any such signal would be very weak (and remain so for some time) given the point in the investment cycle. This is because there are very few major future investment costs to signal, and they are some way off (which reduces the NPV of the relevant costs).
66. Once these economic characteristics of transmission are recognised, it becomes apparent that the current TPM *is cost reflective*. To be sure, the implicit mark-up on incremental cost (or contribution to common costs) varies from region to region (and from customer to customer) – as the Options Paper recognises.⁴⁵ However, that does not mean that the current TPM entails any cross-subsidies or inefficiencies from an economic perspective.
67. Applying varying mark-ups to different customers will often make sound economic sense and promote statically and dynamically efficient outcomes.⁴⁶ In the case of the TPM, the fixed charges that recover the majority of Transpower’s revenue requirement attempt to minimise distortions to grid usage.⁴⁷ As we have explained in previous reports, the TPM therefore bears a strong resemblance to a “Ramsey-Boiteux” two-part tariff, where:

⁴⁴ For a detailed description of the short- and long-run costs of transmission, see: CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, section 3.1.

⁴⁵ Options Paper, footnote 69.

⁴⁶ For example, if some customers are more likely than others to respond in inefficient ways to higher prices, it is better to charge them prices that have a lower mark-ups on incremental costs. Higher mark-ups can then be applied to ‘less price-sensitive’ customers in order to recover total costs.

⁴⁷ As we noted in the previous section, Transpower is reviewing both the HVDC and RCPD charges with a view to addressing perceived distortions in consumption behaviour brought about by the current design.

- the SRMC of transmission grid usage is reflected in the differences in wholesale spot prices between nodes; and
- the fixed costs of existing transmission assets are recovered through a series of fixed charges, with a view to minimising distortions to grid usage.⁴⁸

68. As we noted above, one consequence of this approach is that some customers may pay for assets for which they derive few private benefits. For example, the minimum distortions to grid usage might often be obtained by ‘smearing’ the cost of an existing investment across a large number of users to dilute its effect on any particular customers.⁴⁹ Although that might not seem *fair* in a subjective sense, it is not necessarily *inefficient* in an objective sense.

69. The attendant fear expressed in the Options Paper that the TPM might ‘artificially stimulating growth and investment in growing regions’⁵⁰ is also unfounded. In our opinion, transmission pricing differentials will have no meaningful impact upon comparative regional development outcomes, because:⁵¹

- for the vast majority of New Zealand businesses, energy comprises only a small proportion of total input costs – and so changes in transmission prices will therefore have no effect on their investment decisions and the resulting regional development outcomes; and
- for those businesses for which energy is a major cost there will be other more important factors driving investment decisions, e.g., a pulp and paper mill will locate near to forests, an aluminium smelter will locate near suitable port infrastructure, and so on.

70. In sum, there is nothing inherently inefficient – or ‘not cost reflective’ – about transmission prices that allocate a proportion of the costs of investments to parties that seem not to be the principal beneficiaries, as appears to be *presumed* in the Options Paper. It may be efficient to ‘split the bill’ in this way, as it were. Whether

⁴⁸ To be sure, it is possible that the way in which those fixed costs are recovered still results in some distortions to consumption and attendant inefficiencies. Indeed, as we noted in the previous section, Transpower is reviewing both the HVDC and RCPD charges with a view to addressing some perceived shortcomings in their current design.

⁴⁹ Returning to our hypothetical restaurant, there may be 5 ‘heavy eaters’ that eat more at the buffet than anyone else. Nevertheless, the most efficient way to recover its predominantly fixed costs may be to smear the costs across all customers – including, say, 500 ‘light eaters’. This may soften the impact on any one customer and not discourage anyone from dining.

⁵⁰ Options Paper, §4.14(g).

⁵¹ In a similar vein, Oxera assessed the potential for wider economic effects to flow from a change in the WACC percentile applied to energy network businesses. For similar reasons to those we have set out above, it concluded that there would be no such effects and that they could consequently be ignored. *See: Oxera, WACC consultation. Input methodologies Review of the ‘75th percentile’ approach Prepared for New Zealand Commerce Commission, 23 June 2014, section 4.3.2.*

the current allocation of charges represents a problem is ultimately an *empirical* question that would depend upon a number of factors, as we explain below.

2.2.2 The efficiency consequences of large re-allocations

71. The phenomenon identified in the Options Paper – parties paying for transmission assets under the current TPM that do not provide them with significant benefits – could, *in principle*, lead to static and dynamic inefficiencies. In terms of the former, as we highlighted in our report in response to the Beneficiaries Pay Working Paper, levying charges in a way that does not reflect consumers’ private benefits could theoretically result in:⁵²
 - some parties not consuming the services at all; or
 - some parties not consuming as much of the service as they would have at a price that reflected their actual private benefit.
72. In other words, demand that could have been served at prices that generate positive economic profits could go unmet, producing deadweight loss. It follows that reallocating sunk costs via a reform to the TPM could *potentially* deliver a static efficiency improvement if:⁵³
 - some customers face *lower* prices than under the current TPM and consequently *increase* their consumption; and
 - those customers that face *higher* prices do not inefficiently *reduce* their demand (which depends upon how accurately private benefits are estimated).
73. The key question when assessing the proposed pricing options is whether there is any real prospect *in practice* of reallocations materially reducing inefficiently unmet demand. Our previous reports have expressed the view that the potential for such gains could well be relatively limited – at least in the *near- to medium term*. We remain of that opinion, and note that:
 - as explained above, the two-part tariff structure of the existing TPM is consistent with efficient transmission pricing principles;
 - the Operational Review that Transpower has just completed is likely to limit further the scope for near-term static efficiency gains (see section 2.1.2); and

⁵² CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §46.

⁵³ In contrast, the transfers of wealth between groups of consumers that may occur as a result of the change in methodology are irrelevant to the assessment of static efficiency. The reduced price that one customer receives on all of the units that she would have consumed anyway is simply paid for by another customer, who must now pay a higher price. This does not produce any additional welfare that did not previously exist – it is a bare transfer of current wealth, and welfare neutral.

- should static inefficiencies emerge in the future, Transpower may be in a position to address them expediently through *another* Operational Review.
74. Having said that, it is *possible* that static – and dynamic – inefficiencies might still emerge (or become more pronounced, as the case may be) over the longer-term if interconnection and HVDC charges continue to be levied in the same manner. For example, it is possible that even if the TPM is not *currently* resulting in an inefficient level of unmet demand and distortions to investment outcomes, that this might happen over time as more investments are made.
 75. In particular, the Options Paper raises legitimate questions about the long-term inefficiencies that may arise if the ‘wedge’ between the benefits that customers receive from transmission investments and the charges they pay grows over time under the current TPM. If this disparity grows significantly over time (which it may or may not – see below), the more likely it is that dynamic efficiency will be harmed through customers making sub-optimal investment decisions.
 76. For example, if the HVDC charge increased in the future (e.g., if “Pole 4” was built) and continued to be levied solely on South Island generators (who are not the sole beneficiaries of the link⁵⁴), then this may *over-signal* the additional cost to Transpower of generators locating in the South Island.⁵⁵ At the margin, a generator may consequently choose to invest in the North Island, when locating in the South Island would minimise total forward-looking system costs, i.e., including the costs of transmission *and* generation.
 77. In addition, it is possible that any such ‘wedge’ might grow to a point where some consumers chose not to use the grid at all (e.g., if their transmission charges exceed their private benefits) or, more conceivably, where they alter their conduct in undesirable ways to avoid those outlays, compromising static efficiency. Some of the key issues to examine when gauging the likelihood of these inefficiencies arising under the status quo (or alternative approaches) will include:
 - the probability of future investments actually materially increasing any such ‘wedge’ above and beyond that which exists today – the key points to consider in this respect will include:
 - the balance between replacement expenditure and capital expansions – the former will in most cases be replacing assets that are fully depreciated in

⁵⁴ For example, during times of ‘northward’ flows, North Island consumers benefit from lower wholesale electricity prices. See further discussion in section 8.3.1.

⁵⁵ Note that the extent of this incentive will also depend upon the HVDC charging *parameter*, which is currently under review.

accounting terms, so any step changes in price should be more modest⁵⁶ (assuming straight line depreciation is not applied to individual assets⁵⁷);

- the price levels for existing assets at those future dates, e.g., if Poles 2 and 3 of the HVDC are ‘well depreciated’ in accounting terms, then customers may be paying lower prices for those assets at the time, and the incremental effect of, say, a ‘Pole 4’ may consequently be reduced; and
- the changes that may emerge from Transpower’s Operational Review, and the potential for subsequent reviews to occur if circumstances change in the future, which may reduce the likelihood of distortions to grid use arising over time under the current TPM;⁵⁸
- the likelihood of the TPM adversely affecting the investment decisions of generators and load, given the many of other factors that are likely to enter into such decisions, e.g., the location of fuel sources (water, wind, etc.), the proximity to raw materials (trees, etc.) and so on; and
- when such effects might potentially arise, which influences the NPV of the benefits that can be obtained from seeking to address such issues today which, in turn, goes to the question of whether now is the best time to address any perceived challenges that may emerge in the future.

78. Moreover, as we have explained on myriad occasions in our previous reports, even if there were conceivable long-term static and/or dynamic inefficiencies associated with the allocation of sunk costs under the current TPM, these would need to be weighed against the potential inefficiencies associated with alternatives. As we explain in sections 3 to 7, there are significant shortcomings associated with all of the approaches that have been proposed in the Options Paper in this respect.⁵⁹

⁵⁶ Note that if replacement costs decline over time, these new assets may even be less expensive.

⁵⁷ If the prices that Transpower is able to charge for *individual assets* (e.g., the NIGU lines) are linked to its annual revenue requirement as defined by its Individual Price-quality Path (IPP), there will be large ‘step-changes’ in prices when assets are replaced. This is because straight-line depreciation is ‘front-loaded’ and will allow Transpower to charge the highest prices right after an asset is replaced (when it is relatively ‘undepreciated’) and the lowest right before it is replaced (when it is nearly fully depreciated). However, this is a highly inefficient time profile of charges, and we would therefore recommend strongly against any approaches that yielded such an outcome. See further discussion in section 3.3.

⁵⁸ For example, as we explained in the previous section, the RCPD signal will be ‘weakened’ as a result of the Operational Review and it could subsequently be ‘re-activated’ if circumstances change in the future, i.e., if constraints re-emerge in particular regions.

⁵⁹ For example, as we explain subsequently, the deeper connection and AoB charges would each potentially entail charging prices that exceed the private benefits that customers obtain from the assets in question. However, unlike the current TPM, which tends to distribute costs across a broad base of customers, the proposed options would see charges falling on a much smaller number of customers. The price signals would therefore be more acute, and provide stronger incentives to change behaviour in inefficient ways.

2.2.3 Seeking a ‘fairer’ allocation of sunk costs

79. In our opinion, the concern expressed in the Options Paper about the ‘cost-reflectivity’ of transmission costs appear not to be motivated solely by efficiency considerations.⁶⁰ Rather, they seem to be based also on notions of equity. Although it is not couched explicitly in these terms, the implication is that because Transpower’s recent investments have primarily benefited the North Island it is consequently *fair* for customers in that region to pay more, and for customers in the South Island who have not benefited as much to pay less.

80. This sentiment features prominently in the aforementioned ‘restaurant’ analogy that has been used to rationalise the redistributions associated with the options. Dr Layton characterised the apparent inequity of the existing flat postage-stamp approach charge in the following, rather colourful terms:⁶¹

‘There’s a poor guy at the end of the table who has had bariatric surgery, lost 65kg, unable to drive and can only eat soup and the bread – they are not happy about the even spreading of the bill.’

81. Although this line of reasoning again has intuitive appeal, it is important to realise that it is not necessarily symptomatic of an ‘efficiency’ problem. We explained above that it can be efficient for parties to be allocated a share of the sunk costs of existing assets from which they do not derive significant private benefits if that results in the fewest distortions to demand (it also does not make an allocation ‘not cost-reflective’). Indeed, whether an alternative allocation would be more efficient than the current TPM is ultimately an empirical question.

82. However, that is not to say that there is *no* merit in seeking to implement a more equitable allocation of charges. Indeed, as we note in section 2.4, ‘fairer’ charges have the potential to be less contentious and more durable. For that reason, if changing the TPM to address perceived unfairness would not lead to significant adverse changes in conduct (or if it might even improve static and dynamic efficiency⁶²), then it may be worthwhile incurring the costs of changing the TPM to address that apparent inequity.

83. The trouble, of course, is that unlike efficiency – which is an objective, measurable standard – equity is inherently subjective. What might seem fair to one might seem unfair to another. It can also be affected by intertemporal considerations. For example, whilst it might seem ‘fair’ for the beneficiaries of new investments to pay

⁶⁰ Indeed, as we explained above, the current TPM is ‘cost reflective’.

⁶¹ Weir., J, ‘Power bills could rise in Auckland, Northland under “option”’, (sourced 10 July 2015): see: <http://www.stuff.co.nz/business/money/69425610/power-bills-could-rise-in-auckland-northland-under-option>.

⁶² As we noted above, this is at least conceivable – particularly in the longer term.

for them, it may seem less so if the beneficiaries of past investments have been treated differently – or if there have been other offsetting benefits.

84. It might also be said to be somewhat ‘unfair’ to change the way in which sunk costs are allocated so soon after a major investment programme. Rightly or wrongly, this might be viewed by some as it ‘shifting the goal posts’ and might even undermine the confidence that some participants have in future investment approval processes – and transmission pricing frameworks. Put simply, ‘equity’ is often in the eye of the beholder.
85. It is for this reason that objective efficiency considerations should, rightly, trump subjective equity considerations in regulatory decision making. In particular, if changing the TPM to address perceived inequities in the allocation of costs would lead to inefficient changes in usage and investment decisions, then those inefficiencies should obviate any reform from occurring.⁶³ In our opinion, fairness – whilst relevant – should rightly remain a secondary consideration.

2.3 Discovery of efficient investment

86. It is suggested in the Options Paper that transmission charges have an important role to play in supporting the discovery of efficient investments. It is said that the proposed options will cause parties that would otherwise be disinclined to participate in new investment processes, or would participate in unconstructive ways, to engage and provide the Commerce Commission (Commission) with the information it needs to judge good investments from bad. The paper states that:⁶⁴

‘...it is intuitive that if charges for an investment apply to the parties who would not have their demand met without the investment, parties would be better incentivised to efficiently and effectively scrutinise proposed investments.’

87. Although we agree that this might seem intuitive, a closer examination of the facts and underlying incentives of the parties in question suggests that the potential for TPM reform to positively influence investment outcomes has been overstated. In our opinion, once these matters are properly understood, the theoretical link between transmission pricing reform and superior investment outcomes is tenuous. Moreover, the complexity of the options that have been proposed makes any such relationship even less likely in these particular circumstances.

⁶³ Moreover, in terms of the options that have been presented it would steer one towards ‘Application B’ rather than ‘Application A’.

⁶⁴ Options Paper §3.35.

2.3.1 No evidence of a material problem

88. As we explained in our first report,⁶⁵ no material has been provided to suggest that the Commission’s input methodology (IM) has led to inefficient investment outcomes or that it will do so in the future without TPM reform.⁶⁶ In this respect, it is important to remember that when assessing the success of the investment framework one must avoid the ‘proscription against hindsight’. The efficiency of decisions must be judged in light of the information that was available at the time that they were made, and *not after the fact*. To quote a US regulator:⁶⁷

‘A prudence review must determine whether the company’s actions, based on all that it knew or should have known at the time were reasonable and prudent in the light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company’s managers.’

89. To that end, we note that when the global financial crisis (GFC) struck in late 2008, there was an unprecedented flattening of load growth. When viewed *at that time*, the investments that Transpower had in train – or had recently completed – might consequently have appeared unnecessary or untimely. However, the critical point is that neither Transpower nor anyone else could have anticipated the effects of the GFC *when the investment decisions were made*.

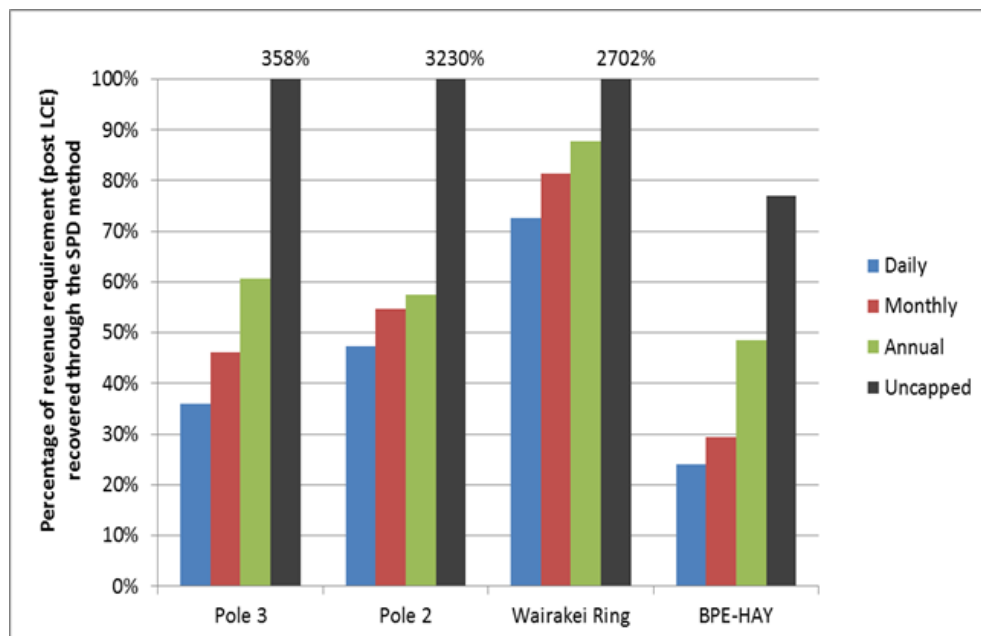
90. It would consequently be inappropriate to conclude, with the benefit of hindsight, that there was something wrong with those initial decisions, or with the investment framework itself. In any event, we note that the material contained in the EA’s TPM workshop presentations indicates that many of Transpower’s major capital projects are now delivering substantial private benefits. This can be seen in the chart below (reproduced from the workshop presentation).⁶⁸

⁶⁵ CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 3.1.

⁶⁶ We note that the EA provided an analysis of the costs and benefits of several recent transmission investments in Table 3 of its Problem Definition Paper that implied that some of those investments were not efficient. However, in our opinion, that analysis was not robust, because they did not account for reliability benefits that do not have an immediate and ongoing market impact. Those estimates are consequently irrelevant, since the greatest benefits of reliability investments tend not to arise during “business as usual” but, rather, when things go wrong. For example, the chief benefit of Orion’s investments in earthquake proofing did not materialise until disaster struck.

⁶⁷ *In re Western Mass. Elec. Col.*, 80 PUR4th at 501, See: Phillips (1993) *The Regulation of Public Utilities* 3rd ed, Arlington Virginia, Public Utilities Reports, Inc, p.340.

⁶⁸ Electricity Authority, *Transmission Pricing Methodology (TPM) Review, TPM options working paper, Workshops, July 2015*, slide 32.



91. The black bars in the chart above show the current annual estimates of the total private benefits being delivered by these major capital investments. In three of the four cases, the private benefits comprehensively outweigh the annual ‘building block cost’ (i.e., annual revenue requirement). Moreover, in the case of ‘BPE-HAY’, we understand that if benefits are assessed over a longer timeframe, a similar pattern emerges, i.e., benefits substantially outweigh the investment costs.
92. In our opinion, these results do not appear to be symptomatic of a ‘failed’ investment framework – even when that assessment is undertaken *with* the benefit of hindsight (i.e., in violation of the principle that we described above). It has therefore not been established that there is a problem with the new investment framework that needs to be solved through greater participation by market participants, even assuming that were achievable.
93. Even if there *was* a problem arising from asymmetric information (i.e., parties not engaging or participating in an unconstructive manner), the proposed options would be unlikely to address it. This is because, as we set out in our response to the Beneficiaries Pay Working Paper,⁶⁹ under any conceivable variant of the TPM, there are likely to be submissions from parties that support an investment and from those that oppose it – regardless of whether it is “good” or “bad”.
94. This is because the participants in the investment process will not be motivated by what is best for the market. Rather, profit-driven enterprises will, quite understandably, want the outcome that delivers the most benefits *to them*. Even if

⁶⁹ CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 3.1.

an investment will maximise overall market benefits, there will inevitably be ‘winners’ and ‘losers’. This will naturally effect what parties have to say to the Commission about any particular investment proposal:

- a party that is not a private beneficiary of a proposed investment (i.e., a ‘loser’) is unlikely to take any solace in the fact that it maximises benefits for the market – it will oppose the proposal because of the negative wealth implications on its business (and its profits); and
- even if a party would be a private beneficiary of the investment (i.e., a ‘winner’) that would maximise overall market benefits, it may still have an incentive to lobby for something else that would deliver it even higher benefits, e.g., a smaller investment – or something built later.

95. The Commission will always have to weigh up a number of conflicting submissions – none of which will be motivated by maximising the net market benefit – and exercise its judgement. It will therefore invariably be its role to ‘discover’ the efficient transmission investment outcome. The TPM cannot short-circuit that process. Nonetheless, the Options Paper suggests that TPM reform might at least *assist* the Commission in that task, as we explain below.

2.3.2 Potential for additional ‘constructive’ opposition

96. The Options Paper submits that if the status quo is reformed, there will be increased – or more constructive – *opposition* to “bad” investments from parties that would be forced to pay under a revised TPM, but would not (or would not to the same extent) under the current methodology. In other words, the contention is that charging beneficiaries would cause submitters to ‘come out of the woodwork’ and provide the Commission with additional information to assist in that discovery of efficient outcomes.
97. In other words, even though there would still be conflicting opinions, there may be some *additional* voices – and they might prove instrumental in bringing about the best investment outcome. In order for that to be the case, two things must happen. First, TPM reform would need to actually bring those new parties ‘to the table’, as it were (or at least result in those parties engaging more constructively). Second, the contribution of *those particular parties* would need to result in the Commission making better decisions.
98. Although we accept that this is certainly conceivable in principle, we do not consider that it is likely in practice. A cursory inspection of the Electricity Commission’s archived website reveals that generators, distributors and major customers were active participants in every major grid investment consultation that was undertaken from 2005 and 2007. It consequently cannot reasonably be said that Transpower’s investment plans were waved through unopposed – there was a collection of

submissions from interested parties in each instance (and, as we set out above, those investments are now delivering substantial benefits).

99. To be sure, there are a number of parties that were affected by those investments which did *not* participate in these processes – including smaller businesses. However, it is perhaps unrealistic to think that these market participants will have the internal resources to engage fulsomely in each and every grid investment decision that affects them. It is therefore an open question as to whether the types of TPM reform being contemplated in the Options Paper would indeed yield a materially larger volume of submissions.
100. The ability of new participants to engage in the investment process in an informed way will also be influenced by the complexity of the TPM. As we explain in sections 3.2 and 3.5, some of the options that are being proposed are extremely intricate and have the potential to overlap over time e.g., deeper connection charges may morph into AoB or SPD charges as grid usage patterns change. This may limit smaller parties’ ability to assess how new investments will affect them and, in turn, their ability to engage constructively in new investment processes.
101. This undermines further the contention that the proposed options would assist in the discovery of efficient investment outcomes. The sheer complexity of the options means that it is altogether more likely that the parties that have been disinclined to engage in the investment processes to date will remain so, or that they will be unable to engage in fully informed debate. There is also a risk that the options will simply give rise to *more opposition* to investments – whether they are ‘good’ or ‘bad’, as we elaborate below.

2.3.3 Potential for additional ‘unconstructive’ opposition

102. If given the option, a regulator will generally prefer to have more information from more submitters than the opposite. However, not all additional material will necessarily be constructive and assist in the best decision being reached. As we explained at length in our response to the Beneficiaries Pay Working Paper, parties that benefit from a “good” investment (i.e., that maximises the net market benefit) may still have a strong incentive to lobby for something else. When deciding whether to support a good investment, a party will ask:
 - will I benefit from this investment?; *and*
 - will I benefit *even more* from a *different* investment, such as:
 - a smaller investment that entailed lower costs?; and/or
 - an investment that took place at a later date when demand is higher?
103. If the answer to either of the questions in the second bullet is “yes”, then beneficiaries may oppose a “good” investment, simply because they would benefit more from another option that offers fewer overall market benefits. As we explain in

subsequent sections, the design of the deeper connection, SPD and AoB charges – including their time profiles – make this outcome highly likely. The options therefore risk creating more *unconstructive* opposition to *efficient* investments. This will not aid the discovery of efficient investments – it will hinder it.

104. The complexity of the options could compound this problem. In our view, it is conceivable that the options may simply prompt more opposition from parties that see that they will need to contribute to the costs of a proposed new investment, but do not fully comprehend the exact prices that they will be required to pay over time (which would be very difficult to model), or the benefits that they will derive. The overall effect may simply be more unproductive, price-shock motivated opposition.
105. Potentially even more problematically, if the increased opposition to “good” investments led to Transpower being made to delay expenditure and/or building smaller assets, there is a risk that this might be viewed as evidence of the reform working. Specifically, parties might surmise that the “stronger incentives” that had been created for beneficiaries to participate in the investment process had revealed that Transpower was proposing to build things “too big and too early”.
106. This might consequently lead to the perception that the revised pricing methodology had prevented those inefficient investments from proceeding, giving rise to substantial dynamic efficiency gains. However, the reality may be quite different. For the reasons described above, the reforms may have instead given parties stronger incentives to advocate against efficient investments, leading to the wrong things being built at the wrong time and substantial dynamic efficiency *losses*.
107. Finally, and more importantly, as we noted above, no robust examples have been provided of the Commission approving “bad” investments or knocking back “good” investments under the existing framework. In other words, no evidence has been presented that would indicate that the investment process has been compromised by either a lack of submissions or a dearth of information. In contrast, there is now clear evidence of the large benefits Transpower’s recent investments are delivering.
108. For those reasons, we do not consider that a strong basis has been provided in the Options Paper to support the contention that TPM reform would promote the discovery of efficient transmission investments. In our opinion, the proposed options would, at best, have no effect on the investment approval process and, at worst, give rise to additional unconstructive opposition to all investments (whether efficient or not), which may serve to compromise dynamic efficiency.

2.4 Durability

109. The Options Paper questions the durability of the current TPM. It notes that issues such as HVDC pricing have been extremely controversial and that the current methodology has been under review in one way or another since it was implemented on 1 April 2008. That is undoubtedly true. However, transmission pricing was a

source of controversy well before the current TPM was put in place.⁷⁰ This is an unremarkable consequence of the economics of transmission.

110. Changes in the TPM that have only modest efficiency implications can still give rise to large transfers of wealth between industry participants. It is therefore only natural that profit maximising firms have lobbied continuously to have the methodology changed in their favour. The willingness of the EA and its predecessor to continue to entertain the notion of reforming the TPM is also likely to have contributed significantly to this conduct.
111. The fact that transmission pricing – and pricing reform – will always give rise to ‘winners’ and ‘losers’ means that it will never be possible to *completely* eliminate controversy and lobbying. Even if the TPM was theoretically ‘perfect’ (which is impossible), there would still probably be parties lobbying to change it, motivated by wealth transfers. For those reasons, the fact that the TPM has been controversial over the course of its existence is not, in itself, a good reason to change it. Another methodology may have been equally controversial – perhaps even more so.
112. In short, the level of lobbying reveals very little – if anything – about the durability of the TPM. In our opinion, the most important determinant of a methodology’s durability is its efficiency. Put simply, efficient methodologies are durable, and inefficient methodologies are not. This is because if a pricing methodology gives rise to undesirable conduct by market participants that compromises grid usage and/or long term investment decisions it will eventually need to be replaced with an approach that mitigates these effects.
113. If a methodology does not give rise to these problems, then it should rightly be considered durable – regardless of the level of lobbying or disputes. Indeed, if the ‘durability’ of a methodology was determined solely by the level of disputation and lobbying, the EA could obtain an enduring methodology simply by stating categorically that it will not contemplate any changes to the TPM for the next, say, ten years. For this reason, we do not view ‘durability’ as distinct objective – if the other components of the TPM are sound, stability should follow.
114. In this respect, it is worth remembering that Transpower recognised the potential problems with the existing design of the HVDC and RCPD charges and the solutions

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For example, Contact and Meridian launched a successful judicial review of the process the EA’s predecessor undertook to arrive at its 2005 pricing guideline, see: *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J).. For an overview of the process by which the current TPM was determined – including the various controversies, see: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.17.

do not require widespread reform.⁷¹ This demonstrates that the TPM can change – and relatively quickly – when it becomes clear that it has inefficient elements.⁷²

115. This suggests that there is ample scope under the current transmission pricing arrangements to address issues through incremental reform, through Transpower's Operational Reviews or, potentially, through targeted refinements of the guidelines by the EA. By comparison, it may only very rarely be necessary to undertake radical reforms of the methodology. In our opinion, this suggests that the current methodology is relatively durable and adaptable.
116. Having said that, as we explained in section 2.2.2, it is *possible* that, even if Transpower's proposed changes are implemented, that inefficiencies may emerge (or become more pronounced) over the longer-term if interconnection and HVDC charges continue to be levied in the same manner. In particular, if the wedge between the charges levied on particular customers and their private benefits grows over time under the current TPM, then this may result in distortions in the long-term, even if it does not now.
117. It is consequently appropriate for the Options Paper to flag this as a *potential* issue that may affect the efficiency and, in turn, the durability of the current TPM over the long term.⁷³ However, as we explained above, whether it is *in fact* a material problem is ultimately an empirical matter and, even if it is, whether it is appropriate to address the matter now – as opposed to at some future date – remains an open question. Moreover, any potential inefficiency in the current TPM would need to be weighed against the shortcomings in the alternative options.
118. Finally, it is worth noting that it is possible that the perceived 'fairness' of the TPM can also affect its durability. If existing prices are widely viewed as inequitable, this can serve to increase controversy and the cost of disputes. For the reasons set out earlier, that is not necessarily problematic in itself if the methodology remains efficient. However, as we explained in section 2.2.3, if a 'fairer' allocation can be achieved without compromising efficiency, there may be merit in doing so.

⁷¹ As we explained above, it is possible that the chief static inefficiencies could be addressed simply by changing the HAMI parameter to an average MWh charge and increasing "N" in the UNI and USI regions – both of which have been proposed by Transpower in its Operational Review. The EA has since accepted some of these recommendations. See: Electricity Authority, *Transpower's proposed variation to the Transmission Pricing Methodology (four components) Decisions and reasons*, 4 August 2015.

⁷² Options Paper, §4.25.

⁷³ Options Paper, §4.24.

2.5 Summary

119. The discussion of the problem definition in the Options Paper provides the clearest articulation to date of the problems with the TPM. In our opinion, the paper raises legitimate questions about the long-term inefficiencies that may arise if the ‘wedge’ between the benefits that customer receive from transmission investments and the charges they pay grows over time. In *principle*, the greater this disparity becomes, the more likely it is that:
 - customers will make sub-optimal investment decisions that impact adversely upon Transpower’s investment costs, harming dynamic efficiency; and
 - parties will alter their grid usage in undesirable ways to avoid those outlays, reducing static efficiency.
120. The Options Paper also raises reasonable doubts about the potential *inequity* of the current allocation of sunk costs. Although it is not couched explicitly in these terms, the implication is that because Transpower’s recent investments have primarily benefited the North Island it is consequently *fair* for customers in that region to pay more, and for customers in the South Island who have not benefited as much to pay less. That view is not necessarily unjustified.
121. In our opinion, if changing the TPM to address perceived inequity would not lead to significant changes in conduct (or if it could even improve efficiency), then it may be worthwhile incurring the costs of changing the TPM to address that inequity. In this sense, ‘unfair’ charges could well be a problem worth examining. Of course, the key challenge is deciding what is and is not ‘fair’. This can be challenging, given the subjective nature of the concept.
122. Although these potential shortcomings are worth exploring in the second Issues Paper, many of the other problems with the current TPM are either mischaracterised or overstated in the Options Paper. For example, despite to the contentions to the contrary:
 - the TPM *has* sent appropriate price signals to market participants in the past and, through Transpower’s Operational Review, it is adapting to send more efficient signals given recent changes in circumstances;
 - the TPM is cost-reflective from an economic perspective, since all grid users face prices that are greater than the SRMC of that usage and less than the ‘stand-alone’ cost of supplying each customer;
 - there is no evidence to suggest that the Commission’s new investment process has produced inefficient investments in the past, or that the proposed TPM reforms would produce superior outcomes in the future; and

- there is ample scope under the current arrangements to address issues through incremental reform, which suggests that the TPM is durable, irrespective of the ongoing controversy, which would persist under *any* option.

123. Despite these shortcomings, for the reasons we set out above, the Options Paper has nonetheless established that there is *potential* for the existing methodology to be more efficient – or at least ‘fairer’. In the following sections, we explore the extent to which the alternative pricing options that have been proposed are likely to address these potential concerns.

3 General Observations

124. In this section we set out some general observations on the proposed options. Most notably, we identify overarching issues that affect all of the proposed alternative pricing approaches to some extent.

3.1 Imprecision and inconsistency

125. Terms such ‘beneficiary’, ‘market-like’ and so have been used extensively throughout every consultation document hitherto – and the Options Paper is no exception. However, these key terms have never been clearly defined and they continue to be applied inconsistently. The analysis in the Options Paper also exhibits several contradictions, including across the different approaches and within particular pricing options.

3.1.1 Imprecise application of key concepts

126. Throughout the Options Paper the ‘decision-making and economic framework for transmission pricing’ continues to be applied. This tool is based on a hierarchy of preferred approaches, with ‘market’ and ‘market-like’ approaches being the most favoured, followed by ‘exacerbators-pay’ and ‘beneficiaries-pay’ approaches, and so on.⁷⁴ In previous reports we have expressed the view that this framework is not especially helpful as a decision making tool.⁷⁵ We remain of that opinion.⁷⁶
127. The framework *might* be of use if key concepts such as ‘beneficiary’, ‘private benefit’, ‘market-like’ and so on were defined with precision. However, they are defined only very loosely in the Options Paper and are interpreted and applied differently across the various charging options. This lack of precision is problematic and is especially noticeable in the design of the SPD and AoB charges:
- the SPD charging approach identifies ‘beneficiaries’ as those parties that are perceived to have benefited from an asset over the previous 3 years, using monthly capping and assumed costs of non-supply; whereas

⁷⁴ Options Paper, Figure 5.

⁷⁵ See for example: CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.3.1.

⁷⁶ In our opinion, the EA’s continued adherence to its decision making framework risks it focussing unduly on inefficient variants of its ‘preferred’ approaches, when alternative approaches may be less distortionary, even though they are further down its hierarchy. See: CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §63.

- the AoB charge assigns 100% of the costs of certain investments to parties identified as the principal ‘beneficiaries’ in the investment approval process, with beneficiaries potentially being updated periodically.
128. Furthermore, as we explain in more detail in sections 4 to 6, in addition to entailing very different approaches to identifying beneficiaries, none of these methodologies is likely to yield an accurate measure of parties’ private benefits. For example:
- the application of a monthly cap (or indeed any cap) necessarily means that SPD charge may not reflect parties’ actual private benefits⁷⁷ – and there is the inevitable potential for modelling error; and
 - as we explain in more detail in section 5, because the pattern of benefits changes over time, the AoB charge – which ‘locks in’ beneficiaries for defined periods⁷⁸ – therefore cannot accurately estimate private benefits.
129. A similar lack of precision arises in the deeper connection charge. The charge is said to be ‘market-like’ on the basis that it captures situations in which, in the absence of a regulator, the parties involved could have otherwise been expected to come together and negotiate an efficient contract for investment. However, it is not. For the reasons we set out in detail in section 4.1.2:
- the proposed criteria will not reflect the situations in which a commercial negotiation would have been feasible – the application of the charge will instead be relatively arbitrary; and
 - the deeper connection charge itself may bear very little resemblance to the net costs that the parties in question would have faced in a hypothetical commercial setting in which they built the assets themselves.
130. For the same reasons (and the other reasons that we set out in section 4.1.2.2), the charge also cannot necessarily be said to identify accurately the ‘exacerbators’ or ‘beneficiaries’ of investments. The way the charge is designed (based on load flow tracing) means that:
- not all exacerbators or beneficiaries will necessarily be charged (as we explain in section 4.1.2.2, certain thresholds are applied that may exclude parties from the charge, even though they are using an asset); and
 - conversely, it is possible that some of the parties that are charged had very little to do with an asset being needed (i.e., did not ‘cause’ the need for the investment) and/or derive few benefits from it.

⁷⁷ For example, the benefits of a reliability investment might accrue in a single period when the presence of that asset prevents a widespread black-out. The resultant private benefits during this small window might greatly exceed the monthly cap.

⁷⁸ Under the ‘static’ option, the beneficiaries are locked-in permanently, i.e., they are never updated.

131. If any of the proposed pricing options are implemented, it would represent a radical departure from the current TPM and from most (if not all) of the transmission pricing models employed internationally. In our view, it is consequently vital that those approaches be informed by clear and compelling guiding economic principles. In our opinion, the proposed options are not. This represents a key shortcoming in the proposals set out in the Options Paper.

3.1.2 Inconsistent rationales

132. The general opaqueness surrounding the interpretation and application of key concepts is compounded by a number of more specific inconsistencies in the analyses throughout the Options Paper. For example, there are ostensible contradictions between:
- the problems that are defined (whether valid or not) with the status quo and the reform options that have been proposed;
 - the approach taken under one charge (e.g., the deeper connection charge) and the approach employed in another (e.g., the AoB charge); and
 - the approaches taken within the same charge, i.e., the proposed ways in which charges have been allocated to different customers.
133. We set out in section 2 the four key problems with the current TPM. Amongst them was the supposedly inefficient time profile of the current charges (see section 2.1), the inefficiency of charging South Island generators based on their HAMI (see section 2.1) and the apparent inability of the existing methodology to aid in the discovery of efficient investments (see section 2.3). Assuming these are indeed material problems, we note that:
- the deeper connection, AoB and SPD charges would all provide inefficient price signals – far worse than those provided under the current TPM which, as we explained above, will change as a result of Transpower’s Operational Review, e.g., the RCPD signal will be ‘diluted’ (see sections 2.1 and 3.2);
 - the Options Paper proposes to apply deeper connection charges to generators based on their AMD, which may incentivise them to strategically withhold capacity in exactly the same way as South Island generators seeking to avoid the HVDC charge under the current TPM⁷⁹ (see section 4.2.1); and
 - assuming that it is possible to improve the investment process through TPM reform (which we doubt – see section 2.3), the options that have been proposed may be too complex for all parties to work out how an investment will affect them, preventing them from engaging constructively (see section 3.5).

⁷⁹ Recall that Transpower has proposed to change the HVDC charge parameter to an average MWh charge to alleviate this inefficiency.

134. There are also inconsistencies between the various pricing options themselves. In particular, the rationales offered for the selection of the charging parameters applied to generators under the deeper connection and AoB charges are contradictory. The Companion Paper states that one of the key reasons to avoid MWh charges when allocating deep connection charges to generators is that they might consequently alter their offers to reflect that additional cost, which would compromise the efficiency of the wholesale market.⁸⁰
135. That is undoubtedly the biggest drawback of a MWh charge to all generators. As we explain in more detail in section 5.2.1, such charges constitute a tax on usage that can inefficiently deter the utilisation of existing assets. Yet, despite acknowledging this problem, the Companion Paper goes on to propose that *AoB charges* be allocated to all generators in precisely this way. The drawback that featured prominently in the analysis of the deeper connection charge remains unmentioned. The Options Paper simply states that:⁸¹
- ‘Allocation to generation on a MWh basis avoids the problem that allocating charges on a capacity basis would disincentivise peaking generation.’*
136. This is plainly inconsistent. Why is disincentivising peaking generation a problem under the AoB charge, but not the deeper connection charge? Equally, why are the distortions to the wholesale market entailed by a MWh charge problematic under the deeper connection charge, but not the AoB charge? These rationales would seem to be irreconcilable. As we explain in section 3.6, this is symptomatic of the fact that, no matter how one seeks to apply transmission charges to all generators, there is the potential for significant distortions to behaviour.
137. Finally, there are some conspicuous inconsistencies *within* the options that have been recommended. As we explain in detail in section 4.7, the Options Paper proposes to allocate AoB and residual charges to EDBs and direct connect customers based on installed ICPs and AMD, respectively.⁸² This difference in approach is not well justified and it results in a dramatic increase in the share of costs recovered from EDBs, e.g., they shoulder 97% of the \$355m residual charge.⁸³ This again seems arbitrary.
138. In summary, the lack of precision surrounding the interpretation and application of key concepts and the numerous inconsistencies throughout the analysis of options is

⁸⁰ Electricity Authority, *Transmission Pricing Methodology Review: TPM options working paper, Companion paper describing the detail of the deeper connection charge*, June 2015, §4.26(b)(ii) (hereafter: ‘Companion Paper’).

⁸¹ Options Paper, §6.78.

⁸² Options Paper, §6.79 and §6.102.

⁸³ EDBs estimated total installed capacity is 47,044MW and major industrial’s cumulative AMD is only 1,252MW, and so EDBs are allocated 97.4% of the 48,297MW total capacity ($47,044 \div [47,044 + 1,252]$).

problematic. The corollary is that the radical (and unprecedented) reform options presented in the Options Paper lack cohesion and contain assumptions that are not informed by any robust, overarching principles. Important elements of those options that have a material impact upon the allocation of charges are consequently not well justified and, in some cases, seem relatively subjective.

3.2 Problematic sequence of charges

139. The Options Paper deploys the ‘decision-making and economic framework for transmission pricing’, and so the *sequence* in which the various charges are applied is determined by their respective positions in that hierarchy. In particular, 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. However, complicating matters is the fact that:

- the ‘AoB’ charge is primarily an *ex-ante* charge, i.e., the objective is to levy charges on the *anticipated* beneficiaries of a new investment (although that group of beneficiaries may be updated over time – see section 5); whereas
- the ‘deeper connection’ charge is an *ex-post* charge, i.e., it identifies deeper connection assets based on historical load flows (measured over a 5-year window) and allocates costs to parties accordingly (see section 4).

140. This difference in application does not necessarily matter when it comes to allocating charges to *existing* assets. They can be classified as ‘deep connection assets’ and charged accordingly from ‘day 1’. However, that is not the case for *new* assets that Transpower might build. These *cannot* immediately be classified as deep connection assets under the options as currently proposed, since there will be no ‘load flow tracing’ data upon which to base that classification. This gives rise to a number of problems, as we explain below.

3.2.1 Application of deep connection charge to new investments

141. Strictly speaking, under the options as currently presented, the earliest that a new investment could be classified as a ‘deep connection’ asset is 5 years after it is constructed. Only then will the necessary historical ‘load flow’ data be available to enable Transpower to potentially ‘reclassify’ the asset if the relevant thresholds are met. In the interim, under the ‘base option’, the costs of the assets will consequently be recovered either through the AoB charge or the residual charge (depending upon whether the AoB criteria are met⁸⁴).

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See: Options Paper, §6.59.

142. This could lead to very unstable prices. It is quite plausible that the costs of a new investment will be recovered via AoB charges for a period (say, an initial 5-year window), only for that approach to switch to a deep connection charge at a future date once the necessary load flow data are at hand – with substantial implications for the incidence of prices. Moreover, depending upon what happens to HHI levels *beyond* that point, assets may switch in and out of the deep connection charge over time as grid usage patterns change. In short:
 - at one point in time a party might be paying significant AoB charges in respect of a particular investment and, at other points in time, it might be paying *no* charges, i.e., if the asset is reclassified as a ‘deep connection asset’; whereas
 - there may be other parties paying AoB charges in respect of the same investment that would see their charges *increase substantially* if it is subsequently reclassified as a ‘deep connection’ asset.
143. In addition to arguably being undesirable in its own right, this volatility will also have adverse effects upon the new investment framework. Put simply, it will make it even more difficult for parties to work out what charges they will pay – and *when*. It is also not altogether clear what information that Transpower would be expected to present to the Commission and interested parties, e.g., would it be expected to identify whether the asset was likely to subsequently be classified as a deep connection asset? If so, on what basis would it make that assessment?
144. Further problems may arise from the fundamental disconnect that may exist between the assets to which AoB and deeper connection charges might be applied. AoB charges tend to apply to a particular grid upgrade, and will consequently comprise a *group* of assets, such as the NIGU lines. In contrast, deeper connection charges may apply to only a *subset* of any particular group of assets, e.g., they might be applied to just *some* of the assets within the broad suite of NIGU lines that meet the HHI thresholds at any particular time. This means that:
 - it is possible that a collection of assets – such as the NIGU lines – will ‘begin life’ with an AoB charge being applied, only for certain assets within that group to be subsequently reclassified as a deeper connection assets; and
 - there will also be *existing* investments – such as the Wairakei Ring – approved under either the GIT or major capital expenditure frameworks where some lines are earmarked for deeper connection and some are not.
145. This difficult this creates is that the AoB charge identifies the beneficiaries of the *total group* of assets that comprise a major investment – it does *not* provide a granular account of the beneficiaries of *individual assets*. There is consequently no clear way to ‘recalibrate’ and ‘reapply’ the AoB charge to a *narrower* group of assets once certain lines reclassified as deeper connection and removed. One option would be to ‘pro-rate’ the AoB charge, i.e., to scale down proportionately the prices that all of the *ex-ante* beneficiaries are required to pay.

146. The problem with this approach is that the ‘new’ deeper connection charges may be levied on only a small number of parties – and they may be the *only assets* within the broader group from which they derive material private benefits. In other words, they may derive little if any benefit from the ‘residual’ assets to which the more narrow AoB charge would then apply. Because the beneficiaries of the AoB charge are not initially identified with this degree of specificity, there would be no way of knowing that and, as a consequence, those parties would essentially be:
- paying potentially substantial deeper connection charges for the assets for which they are assumed⁸⁵ to derive significant benefits; and
 - paying AoB charges for a residual group of assets from which they derive little or no benefit.
147. Another approach would be to undertake a further quantitative exercise to identify the beneficiaries of the narrower group of assets whenever a sub-set is reclassified. Although this might avoid the anomalous scenario described above – and others like it – there is an obvious drawback. Specifically, it could result in never-ending re-assessments of beneficiaries and AoB charges as assets transitioned in and out of the deeper connection framework. In our opinion, that that would create an intolerable degree of uncertainty.
148. For those reasons, in our opinion, it is very difficult to see how the charges in the Options Paper can feasibly co-exist in an intertemporal sense as currently designed. In particular, it seems neither workable nor efficient for assets to be potentially switching in and out of the deeper connection framework over time. Short of implementing a wholly different approach (such as those we set out in section 8), there would seem to be only two potential ways of mitigating this problem – both of which present their own difficulties, as we explain below.

3.2.2 Continue to prioritise the deeper connection charge

149. The first means of reducing the problem raised above would be to continue to give ‘priority’ to the deeper connection charge (i.e., apply it before the AoB charge), but to allow it to be applied to *new investments* as well. Because 5 years of load flow data will not be available, this will necessitate the use of *forecasts*. One approach might be to run scenarios with additional assets hypothetically *inserted* into the grid.⁸⁶ That modelling might then inform whether an asset should be classified as deep connection ‘on day 1’, or subjected to an AoB charge.

⁸⁵ As we explain in section 4.1.2, this may also be a false assumption.

⁸⁶ This would essentially be the opposite of the ‘counterfactuals’ under the proposed SPD charge, which postulate assets being removed – see section 6.1.

150. This might enable a set of indicative forecast deeper connection prices to be estimated and socialised with interested parties during the investment approval process. Then, once the asset had been built (assuming it is built), the continued application of the deeper connection charges would be dependent upon *actual* observed load flows. One critical design question is *how many years* of actual load flow data would be required before an asset can be reclassified.
151. For example, suppose that an asset is initially classified as a deep connection asset, based on modelled forecast load flows. What happens if, at the end of the first year of the asset's life, the actual load flows turn out to be quite different from those forecast, and the relevant HHI thresholds are not met? The first option would be for the asset to immediately cease being a deep connection asset and to become subject to either the AoB or residual charge. However, this approach would create a number of problems:
 - it would create a clear inconsistency between the way that 'existing' deeper connection assets were classified (i.e., with 5 years' of data) and newly built assets were assigned (i.e., over a narrower window);
 - it begs the question of what happens if in, say, the following year (year 2) the load flow analysis indicates that the HHI thresholds *are* met (either in that year alone or on average over the 2 years) – is the asset reclassified again?; and
 - if parties knew that their conduct over a 1 year window might determine how a recently built asset would be classified, they may have an incentive to change their behaviour to affect that determination.
152. An alternative option would be for a newly built asset to remain subject to a deep connection charge until 5 years' of actual load flow data were available. If the HHI thresholds were not met over that longer period, then the asset could be reclassified at that time. In the meantime, parties would have to pay deeper connection charges based on the *forecast* load flows. This methodology has the potential advantage of being more consistent with the treatment of *existing* assets (since the same time periods are used), but there are other significant drawbacks, including:
 - if the *actual* HHI thresholds are not met while parties are waiting for the initial 5 year period to expire, they might reasonably complain that they are being unduly penalised for inaccurate forecasting; and
 - this will greatly increase the significance of the initial modelling exercise, since it would determine who pays deeper connection charges for the initial 5 year period – this would inevitably lead to greater controversy and dispute.
153. In our opinion, there are no clear solutions to these problems and, even if there were, the more fundamental problems described above would remain. First, assets might still transition in and out of the deeper connection charging framework over time as circumstances change. Specifically, there is still the distinct possibility that an asset will be subjected to an AoB charge on 'day 1', only for grid usage patterns to

change and for it to be *subsequently reclassified* as a deep connection asset – *or vice versa*.

154. As we explained above, these reclassifications may give rise to unwelcome price volatility and are likely to complicate significantly the new investment framework. Parties will have very little idea of the charges they will be required to pay over the life of the asset, which will compromise their ability to engage constructively. This is clearly at odds with one of the fundamental objectives of the proposed pricing options, i.e., to facilitate greater positive engagement on investment proposals.
155. Second, there would still be the problem of what to do when only *some* of the assets to which an AoB charge has been applied are reclassified and subjected to a deeper connection charge. As we set out earlier, there would seem to be no robust way of reconfiguring the AoB charges that are applied to the *narrower* suites of assets when these transitions occur, short of constantly reassessing beneficiaries, which could be an unwieldy task and that would create substantial uncertainty.
156. One means of mitigating the problems associated with these ‘transitions’ between charges is to simply *not allow them*. That is, a position might be taken that if an asset is subject to a deep connection charge on ‘day 1’, that charge would *always* be applied – and likewise for assets initially subject to AoB charges. However, insofar as the *deeper connection charge* is concerned, that cannot be done. Transpower could not credibly commit to apply a deep connection charge to an asset in perpetuity, since circumstances may transpire to make this impossible.
157. A straightforward example would be when two large users were the only parties paying deeper connection charges for an asset and they then disconnect from the grid (for whatever reason). In these circumstances, Transpower may have no other plausible candidates upon whom to levy a deeper connection charge – even if it wanted to. It would consequently have no choice but to recover the costs of the asset through the AoB charge or a residual charge.⁸⁷ In short, it is simply not plausible to ‘lock in’ a deeper connection charge indefinitely.
158. In any event, many of the assets to which the Options Paper proposes to apply deeper connection charges ‘from day 1’ are *existing assets* that form part of a ‘broader’ investment such as the Wairakei Ring. Locking in those deep connection charges therefore would not solve the aforementioned problem of how to recalculate and reapply the AoB charge to the smaller group of assets, e.g., only the beneficiaries of the *whole Wairakei Ring* will have been identified in the original investment proposal documents.

⁸⁷

As we explain below, the proposal is to apply the AoB only to investments that meet certain thresholds – which we set out subsequently. If these thresholds are not met, it will not be possible to switch to an AoB charge and a residual charge will need to be applied instead.

159. It follows that, if the deeper connection charge continues to be given priority, the adverse effects described above are unavoidable. However, these problems do not affect the *AoB charge*. If an AoB charge is applied from ‘day 1’ it *can* be retained indefinitely – including as circumstances evolve. For example, if grid usage patterns change and the HHI thresholds are met (that would otherwise have seen a deeper connection charge applied), this could simply be ignored.⁸⁸ This brings us to our second potential solution – to give priority to the *AoB charge*.

3.2.3 Prioritise the AoB charge

160. If the AoB charge was applied *before* the deeper connection charge then, for each major new investment, the principal beneficiaries would be identified and the relevant costs allocated accordingly. Those assets could then be *quarantined permanently* from other charges to avoid the undesirable volatility associated with assets transferring between charges. While the group of beneficiaries from whom the costs are recovered *might* be periodically revisited (so as to reflect changes in grid use in charges over time – see section 5), the assets themselves will *always* remain subject to AoB charges. This would mean that:

- assets would not transition in between the deeper connection and AoB charges over time, because:
 - if an asset is initially assigned to the AoB charge, that charge will always be applied in preference to a deeper connection charge, since it is given precedence in the pricing framework; and
 - if an assets is initially classified as deeper connection, it will only be because the AoB charge criteria (see below) are not met⁸⁹ – in which case an AoB charge can never be applied; and
- there would never be any need to ‘reapply’ an AoB charge to a narrower sub-set of assets, since those groups of assets will never be disaggregated.

161. In principle, there is no reason why the current sequence of charges cannot be reordered in this fashion, since it is based on the belief that the deeper connection charge is ‘market-like’ (as we explain in section 4.1.2, it is not). However, any such revision would have extensive ramifications for the options that have been proposed. Most notably, it will mean that many of Transpower’s past investments that are currently classified as ‘deep connection’ assets in the Options Paper would need to be reclassified and subjected to AoB charges.

⁸⁸ Note that if beneficiaries are periodically updated in the manner described in the Options Paper (see section 5), such changes in grid use will in any case be reflected in AoB charges over time to some extent.

⁸⁹ There is no other way in which a deeper connection charge can be applied in preference to an AoB charge if this resequencing is done.

162. This would be a large undertaking, since many of the investments that have been earmarked for deep connection charges would indeed meet the criteria for AoB charges to be applied.⁹⁰ It would also reduce substantially the role of the deeper connection charge in the overall pricing framework. Specifically, the charge would only apply to investments:⁹¹
- approved and commissioned in the period from 28 May 2004 until the publication of any guideline to introduce an AoB charge, with a cost less than \$50m; and
 - either approved or commissioned (or both) following publication of any guidelines with a cost less than \$20m.
163. It is consequently unclear whether there would be significant benefit from retaining the deeper connection charge *at all* if this approach is adopted – recognising that, of the two potential solutions described above, it appears to entail the fewest drawbacks.⁹² To that end, in section 8, we propose a number of alternative pricing approaches that do not give rise to the intertemporal problems described above – some of which do not incorporate the proposed deeper connection charge.

3.3 Time profile of charges

164. The Options Paper correctly states that static and dynamic efficiency requires price signals to strengthen *before* an investment is made – not afterwards. The supposed lack of such price signals is said to be a key problem with the current TPM. However, as we explained in section 2.1, this concern is overstated. Moreover, we note that many of the proposed new options exhibit the very profile of charges that is thought to be troublesome.

3.3.1 Inefficient price signals

165. With the exception of the LRMC charge (and setting aside the LCE and kvar charges), none of the other options – the deeper connection charge, the AoB charge or the SPD charge – would provide a price signal to users *before* an investment is made. They would all do so *afterwards*.⁹³ This is the case irrespective of whether

⁹⁰ Another key question would be whether to allocate those AoB charges to the beneficiaries identified in the original investment approval documents, or based on an assessment of the beneficiaries of those assets *today*.

⁹¹ Options Paper, §6.59.

⁹² Note that if the deeper connection charge is retained but is applied *subsequent* to the AoB charge if, at any stage, the HHI thresholds cease to be met, those assets would switch into the residual charge.

⁹³ The only way in which the implications of new investments would be signalled to customers *beforehand* is through the new investment process – as is currently the case. We note that the Options Paper states that the options will give rise to a more efficient investment approval process by providing greater

‘Application A’ or ‘B’ is implemented (see section 7). The particular design of these charges also gives rise to additional problems.

166. Specifically, the deeper connection, AoB and SPD charges are linked to the annual revenue that Transpower is permitted to recover for the assets in question under its individual price-quality path (IPP). That revenue requirement is based on a return on and of the depreciated regulatory asset values (a depreciated replacement cost). That represents a problem, because Transpower is required to apply *straight-line depreciation* to those asset values under the Commission’s IM.
167. Straight-line depreciation is a relatively arbitrary accounting allocation, the chief virtue of which is simplicity. When it is applied to a bundle of assets of different ages within a regulatory asset base or pool (as occurs for most energy businesses) for the purposes of setting prices, this arbitrariness does not much matter. This is because prices are usually set for ‘services’ (e.g., distributed electricity), irrespective of the particular assets that deliver them.
168. However, here it suggested that straight line depreciation be applied to set the prices that apply to *individual* assets, i.e., the proposal is to *disaggregate* the asset base (a similar approach was proposed for connection assets in the Connection Pricing Working Paper⁹⁴). That is an altogether different story. It is demonstrably *inappropriate* to apply straight line depreciation to set the price profiles for individual assets or services. Doing so gives rise to two problems.
169. First, it will yield an inefficient time-profile of charges whereby prices are highest immediately after a new asset has been built (i.e., when no straight-line depreciation has been applied) and lowest right at the end of its estimated life when the asset is nearly fully depreciated. In other words, prices would be highest when the forward looking LRMC was lowest (as well as the quantum of private benefits) and vice versa. This is precisely the problem that is said to exist with the current version of the TPM (although, as we explained in section 2.1, that problem is overstated).

incentives to perceived beneficiaries to engage constructively. However, as we explained in section 2.3, in our view, there is good reason to think that those options would have relatively little positive impact upon those processes, and on the investments ultimately made. To the extent its options have any effect at all, it is likely to be through encouraging additional, unconstructive price-shock motivated opposition – including to ‘good’ investments.

⁹⁴ Specifically, the EA has stated that Transpower’s connection charges ‘appear not to be fully cost-reflective’ because the asset charge component is based on average depreciation for all connection pool assets, and the operating cost allocation is calculated using broad allocators rather than actual cost. For the same reasons that we set out in section 2.2, the connection charges *are* cost-reflective. Moreover, for the reasons we set out in the remainder of this section, the EA is wrong to suggest that Transpower’s ‘pooled’ approach is inefficient.

170. We explained this issue in detail as it relates to the SPD charge in our response to the Beneficiaries Pay Working Paper.⁹⁵ The Options Paper acknowledges this problem as it pertains to that particular charge, i.e., it is noted that consideration is being given to whether to allow recovery based on non-depreciated asset values (an approach proposed by Transpower).⁹⁶ However, it has not been recognised that there is an analogous problem with the deeper connection and AoB charges.
171. Second, if two assets – one old and one new – are providing an equivalent service, it is impractical and counterintuitive to charge different prices based on their ages.⁹⁷ Doing so can create problems. For example, once an asset is nearly fully depreciated customers may naturally be reluctant to face a significant step change in price for a new asset that delivers much the same service.⁹⁸ If those customers start exerting pressure on Transpower to ‘sweat’ old assets, this could have adverse implications under its quality path.

3.3.2 Potential solutions

172. There are several ways to address this inefficient time profile of charges. For example, in the regulated telecommunications sector, the Commission uses annuity compensation to set prices for services provided by old assets based on the costs and lives of newly installed assets. Application of a simple ‘constant’ annuity would result in an asset earning the same return on and of capital in each year of its life. The relevant formula is as follows:

$$\text{Constant Annuity} = A = \frac{ORC \times r}{1 - (\frac{1}{1+r})^L}$$

Where:

A	=	Annuity revenue that recovers ORC over L years
ORC	=	Optimised replacement cost
r	=	The discount rate or WACC
L	=	The economic life of a new asset

⁹⁵ We explained this problem as it relates to the SPD charge in detail in our response to the Beneficiaries Pay Working Paper. See: CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.3.2.

⁹⁶ Options Paper, §8.17-§8.20.

⁹⁷ Indeed, in competitive markets firms like Air New Zealand do not vary their standard economy class fares because a plane was built in, say, 2001 rather than 2006.

⁹⁸ We note that in its Connection Charging Working Paper, it is suggested that, in the absence of such a ‘step change’ in price, customers may be motivated to *overstate* their need for a new asset and that Transpower has an incentive and ability to acquiesce to those requests. However, in its submission in response, Transpower explains convincingly why its customers have no incentive to act in this manner, why it would have no incentive or the ability to blithely accept such requests if they were forthcoming and why there is no evidence of such conduct occurring in practice. We agree with this analysis.

173. This means that an asset that is built today for \$100 (i.e., ORC=\$100) and that will last for 10 years (i.e., L=10) and require a WACC of 10% (i.e., r=10%) will earn a combined return on and of capital of \$16.27 in each of the 10 years of its economic life. In contrast, if straight line depreciation was applied to the same asset, the return on and of capital would be front loaded – beginning at \$20 in year 1,⁹⁹ falling to \$19 in year 2,¹⁰⁰ and declining to \$11 in year 10 (after which it would be fully depreciated in accounting terms).¹⁰¹
174. Another option is to use non-depreciated asset values and apply an average depreciation charge. This is the approach that Transpower uses to set the ‘asset charge’ in its connection pricing (this was a key focus of the Connection Charging Working Paper) and this is also the approach that it has proposed be applied within any SPD charge (if it is implemented). Consistent with the connection charging framework, under this approach, charges could be based on the average depreciation to *all* assets to which a form of charge is applied, e.g., all deeper connection assets.¹⁰²
175. The key feature of each of the options described above is that they would remove the distinction between old and new assets that would otherwise give rise to inefficient signals. They might also reduce significantly the price increases facing certain customers. For example, customers deemed to be using ‘new’ assets such as the NIGU lines (Vector), the NAaN lines (Vector Northpower and Top Energy) and the West Coast Upgrade (Westpower) would face smaller increases, since the charges would no longer be ‘front-loaded’.¹⁰³

3.4 Recognising economies of scale

176. The previous section described the problem with the *time profile* of many of the proposed charges. There is also a potential problem with the proposed *levels* of the deeper connection and AoB charges. In particular, both of these charges would involve recovering 100% of the annual revenue requirement for those assets from

⁹⁹ Namely: $(\$100 \div 10) + ([\$100 - \$0] \times 0.1)$.

¹⁰⁰ Namely: $(\$100 \div 10) + ([\$100 - \$10] \times 0.1)$.

¹⁰¹ Namely: $(\$100 \div 10) + ([\$20 - \$10] \times 0.1)$.

¹⁰² The charge would average the rate of straight line depreciation across all deeper connection assets for the purposes of calculating deeper connection charges. This would effectively flatten the profile of charges applied to each bespoke asset.

¹⁰³ As we explain in more detail in section 7, the amendments described above might achieve what the transition mechanisms appear to be designed to attain. Specifically, they may enable a ‘middle ground’ to be found between the relatively benign reallocation of prices entailed by Application B and the much more extensive rebalancing involved with Application A. As we explain subsequently, none of the transition mechanisms that have been proposed can achieve this goal, without giving rise to significant near- to medium-term inefficiencies.

particular users – irrespective of whether they may have been built, in part, to cater for *future* users, or to deliver broader benefits to *other* users.

177. In this respect it is important to remember that transmission investments exhibit significant economies of scale, whereby higher capacity links are almost always cheaper in unit cost terms. This is because, once the land has been purchased and the towers built, there is not much difference in cost between a low and a high capacity line. There are also often more than private benefits at stake. For example as Green et al (2009) explain:¹⁰⁴
 - increased transmission can reduce market power and increase network reliability, both of which deliver benefits that extend beyond the ‘primary’ beneficiaries of an assets; and
 - there are also likely to be valid national security interests to ‘err on the side of caution’ by investing building ‘bigger and sooner’ than risking the alternative, i.e., building ‘too small or too late’.
178. For these reasons, rather than building an asset sized to meet the near-term needs of existing users (of whom there might only be a small number), it will often be more efficient for Transpower to build a larger link, sized to handle demand that may not emerge until some later point – potentially from other parties. This has potentially significant ramifications for the design and administration of the proposed deeper connection and AoB charges.
179. For example, imagine that Transpower is proposing to build a new line to provide additional capacity to, say, a small number of generators in a remote location. Imagine also that the investment that will maximise net market benefits is a line that exceeds significantly the capacity that the existing generators require, e.g., because more customers are expected to emerge in the future and also use the link. And suppose finally that either:
 - the forecast supply-side HHI would be sufficiently high for the asset to be classified as a deep connection asset, such that the generators would be required to pay deeper connection charges, i.e., assuming that such charges could feasibly be applied to applied to the new investment from day 1;¹⁰⁵ or
 - alternatively, that the existing generators would be considered the principal ‘private beneficiaries’ of the new investment, and would consequently be

¹⁰⁴ Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, pp.9-10.

¹⁰⁵ As we explained in section 3.2.2, under the options as currently opposed, there is no mechanism for a new investment to be immediately classified as a deep connection asset and it is not altogether clear whether there is a robust solution to this problem.

required to pay AoB charges (assuming the HHI threshold was not met) throughout the life of the asset.

180. In these circumstances, the existing generators would not support the proposed investment. They would, naturally, advocate for the construction of a smaller line that is sized to meet their own requirements. However, that would not represent the best outcome from the perspective of the market as a whole, because it would ignore both the strong economies of scale and the potentially broader benefits associated with facilitating more competition in the future.¹⁰⁶
181. If the proposed charging options resulted in the smaller line being constructed it would represent an unambiguous failure in the transmission pricing framework. Moreover, as we explain further in the following sections, if the bigger line was constructed, although that would be the superior investment outcome, the way that the proposed options are designed may cause parties to alter their behaviour in inefficient ways to mitigate their exposure to the charges, or, even worse, to exit the market.
182. In our opinion, the deeper connection and AoB charges have been designed without sufficient consideration for these important practical factors that influence transmission investments in a regulatory setting. As we explain in more detail in the following sections, the likely consequence is that, if implemented, those charges would prompt parties to lobby for inefficient investments or to change their grid usage in sub-optimal ways – both of which would harm efficiency.

3.5 Considerable complexity

183. A particularly striking aspect of the proposed options is their complexity. We explained in section 3.2 that if the reforms proceeded then, depending upon the option implemented, the ‘new’ charges that Transpower would be required to administer might include: connection charges,¹⁰⁷ LCE charges, static reactive charges, deeper connection charges (based on complex load flow tracing algorithms), AoB charges (based on past investment approval decisions) and either an LRMC charge or an SPD charge.
184. If Application B is adopted, Transpower would also need to continue applying the existing HVDC and interconnection charges. In addition to the sheer number of charges, it should also be recognised that a number of the components – including

¹⁰⁶ As we explained in section 2.3, this illustrates one of the key flaws in the contention that the options will lead to additional constructive engagement on investment proposals. Here, the principal beneficiaries would *not* support an investment that maximises net market benefits because their own *private benefits* would be greater if an inefficient investment took place, i.e., something smaller, or built at a later date.

¹⁰⁷ These might be the same as the status quo, but the EA has not ruled out changes.

the deeper connection, AoB and SPD charges – also involve complex quantitative modelling. We are not aware of any transmission pricing methodology that is as novel or complex as the approaches proposed in the Options Paper.

185. There are examples from other jurisdictions of transmission network operators implementing something similar to some of the *individual* charges set out in the Options Paper. For example, the Options Paper notes that the Mid-west Independent System Operator employs a methodology that is similar to the proposed AoB charge.¹⁰⁸ However, we are unaware of any system operator or regulator that has contemplated implementing so many complex charges *in combination*. In our opinion, that raises a number of questions.
186. First, as we explained in section 3.2, there is a legitimate question as to whether it is realistic or reasonable to expect Transpower to design and administer simultaneously so many different charges. Second, and even more importantly, the sheer complexity of the methodology raises inevitable questions about whether industry participants will be able to fully understand the methodology, predict its impacts upon them and engage in informed consultation.
187. Indeed, a key aspect of the problem definition is the proposition that TPM reform will provide parties with stronger incentives to engage in future investment processes that affect them, which will lead to superior investment outcomes. As we explained in section 2.3, in our opinion, that belief is likely misplaced. However, even if it is not, it remains the case that parties can only make a meaningful contribution to investment processes if they can comprehend the methodology.
188. We very much doubt whether all affected parties would be able to gauge accurately the long-term effects of a proposed transmission investment under the proposed options. To be sure, larger parties such as the major vertically integrated retailers may have the institutional know-how to model the prices that they are likely to pay. However, we are not convinced that smaller participants will be as well placed – and it is these businesses that the reforms are presumably intended to ‘bring to the table’, since it is they that have been ‘missing’.
189. It is not our intention to disparage the internal capabilities of smaller participants. We simply question whether they can realistically be expected to have the institutional resources to engage in the complex modelling that would be required to assess the potentially complex interaction between the charges over time. For example, as we explained in section 3.2, under the options as currently proposed, assets may transition between the deeper connection and AoB charges over time. These interfaces may be difficult to predict – even for larger participants.

¹⁰⁸ Options Paper, §9.49(c).

190. This undermines further the contention that the proposed options would assist in the discovery of efficient investment outcomes. The complex nature of the methodologies being proposed means that it is far more likely that the parties that have been disinclined to engage in the investment processes to date will remain so, or that they will be unable to engage in fully informed debate. In terms of the latter, there is a clear risk that the options will simply give rise to more opposition to investments – whether they are ‘good’ or ‘bad’.
191. Specifically, the options may simply prompt more opposition from parties that see that they will need to contribute to the costs of a proposed new investment, but do not fully comprehend the exact prices that they will be required to pay over time (which would be difficult to model, given the potential interactions), or the benefits that they will derive. Put another way, the proposals may simply precipitate more unconstructive, price-shock motivated opposition.

3.6 Charging generators

192. One of the key differences between the existing TPM and the various approaches proposed in the Options Paper is the greater number of charges that will be levied upon generators. Currently, all generators pay connection charges and South Island generators pay HVDC charges. Under the proposed options, generators would continue to pay connection charges, but they would also pay deeper connection charges and AoB charges – and possibly either SPD or LRMC charges.

3.6.1 Potential static inefficiency costs

193. In our first report we set out how the New Zealand wholesale market design is directed towards promoting competition between generators that produces prices that reflect their SRMCs. We explained that, although generators are permitted to offer their capacity at any price, the existence of competing offers normally¹⁰⁹ constrains the wholesale prices that they can bid. For this reason, generators:
 - can generally be expected to offer to supply the market at a price that reflects their short run operating and maintenance cost (SRMC);¹¹⁰ and

¹⁰⁹ For example, a base load generator that bids substantially above its operating and maintenance costs risks not being dispatched and being forced to incur the expense of shutting down and restarting its plant. Wholesale prices should only exceed the SRMC of the ‘marginal generator’ when there is a possibility that the existing generation capacity will not be able to meet demand (and prices in the market must rise to reflect the increased SRMC of curtailing that excess demand) or when temporal or sustained market power is being exercised, e.g., when generation is being strategically withheld. For a more comprehensive discussion, see: Green et al, *Potential Generator Market Power in the NEM, A Report for the AEMC*, 22 June 2011; and CEG, *Barriers to entry in electricity generation, a report for the AEMC*, June 2012.

¹¹⁰ For hydro plants, this will include an endogenously determined opportunity cost of water.

- will generally be scheduled to run in line with their economic ‘merit order’, i.e., with the lowest cost plants being dispatched first, and so on.
194. The incentives created for efficient least-cost dispatch is a key feature of the New Zealand wholesale market, and is one of the reasons that it is widely acknowledged as being at the forefront of international best practice.¹¹¹ It follows that anything that *adds* to the SRMC of operating plant will be reflected in wholesale bids. If these are not ‘true’ marginal costs, then this may compromise the efficiency of the dispatch process. Similarly, charges that cause generators to change their behaviour to reduce the incidence of these costs risk causing similar distortions.
195. The Options Paper acknowledges that the deeper connection, AoB and SPD charges all have the potential to give rise to these types of static efficiency problems. In our opinion, irrespective of the way in which transmission costs are allocated to all generators, it is difficult to avoid distortions to grid use. For example, as we explain in more detail subsequently when we explore the specific charges themselves:
- peak charges based on anytime maximum injection (or HAMI) may lead to generators strategically withholding capacity (see section 4.2.1);
 - MWh charges may be factored into wholesale bids, which may result in inefficient wholesale dispatch (see section 5.2.1); and
 - capacity based charges may cause generators to inefficiently decommission plant, or eschew adding it.
196. The net result in all cases may be significant static inefficiencies and higher prices. In other words, there is obvious potential *efficiency costs* associated with changing the way that transmission charges are levied on all generators, i.e., by introducing deeper connection, AoB and SPD charges. Whether there are significant potentially *efficiency benefits* is, in our opinion, rather less clear.

3.6.2 Potential dynamic efficiency benefits

197. We indicated above that it is possible that changing the way that transmission charges are currently allocated to generators under the TPM could yield more *dynamically* efficient investment outcomes in *some* circumstances – particularly over the longer term. As we explained in section 2.2.2, one potential example of this is the HVDC charge.
198. If the HVDC charge increased in the future (e.g., if “Pole 4” was built) and continued to be levied solely on South Island generators (who are not the sole beneficiaries of

¹¹¹ For example, see: Hogan, W. W, ‘Electricity Market Restructuring: Reforms of Reforms’, *20th Annual Conference, Center for Research in Regulated Industries*, Rutgers University, 25 May 2001, pp.22-23.

the link¹¹²), then this may *over-signal* the additional cost to Transpower of generators locating in the South Island.¹¹³ At the margin, a generator may consequently choose to invest in the North Island, when locating in the South Island might minimise total forward-looking system costs, i.e., including the costs of transmission *and* generation.

199. However, in other circumstances – perhaps the substantial majority of cases – transmission pricing differentials may have relatively little impact upon where and when generators invest. Generators may instead decide to locate their plants based primarily on the availability of certain fuels, such as access to fossil fuel, geothermal or wind energy. For these types of generators, the locational variation in access to energy sources may greatly exceed even the largest feasible locational differentiation in transmission charges.¹¹⁴
200. Similarly, locational decisions may be influenced by pragmatic factors such as the need to obtain the appropriate resource consents.¹¹⁵ Generators will also need to weigh up several other considerations arising out of the regulatory framework, such as the connection charge that it will need to pay (which would be the same under the current TPM and the proposed options), whether they will face any transmission constraints and, relatedly, whether those constraints are likely to be ‘built out’. As Green et al (2009) explained at length:¹¹⁶
 - the principal reason for favouring the current deep connection charge was to encourage connecting parties – including generators – to make efficient location decisions for their plant, by trading off the additional costs of locating at various points with the additional costs of connection;¹¹⁷
 - the nodal pricing and dynamic loss factor regime provides generators with an incentive to choose locations in the network that mitigate transmission losses

¹¹² For example, during times of ‘northward’ flows, North Island consumers benefit from lower wholesale electricity prices. See further discussion in section 8.3.1.

¹¹³ Note that the extent of this incentive will also depend upon the HVDC charging *parameter*, which is currently under review.

¹¹⁴ In these circumstances, transmission charges have little or no effect on overall economic efficiency. Provided the price of these external factors is determined in competitive markets, we can assume that those prices reflect the marginal cost of the relevant inputs. Any resulting locational incentive arising from those input prices is therefore efficient and can be put to one side.

¹¹⁵ For example, if a potential location is covered by an existing consent, and an alternative location would require a new consent to be obtained this may be a decisive factor in selecting the former location if the consent approval process is likely to be costly and protracted.

¹¹⁶ Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, section 4.

¹¹⁷ Electricity Commission, *The Commission’s Statement of Reasons in relation to the Proposed Guidelines for Transpower’s Pricing Methodology*, 18 February 2005, §98 and 99.

and network congestion, i.e., a generator that locates on the ‘wrong side’ of a constraint or in a location with high generation loss factors is likely to be foregoing operating profit as compared with another location;¹¹⁸ and

- Transpower’s capital expenditure IM provides no guarantee to a generator that locates behind a constraint that it will be ‘built out’, i.e., if the net market benefit would be maximised by Transpower *not* upgrading the network to alleviate the constraint, then the generator will continue to be constrained off and may eventually be stranded – that is the risk it takes.

201. In other words, there are a variety of considerations that will determine where (and when) a generator will choose to invest in new plant. In our opinion, with the limited exception of the HVDC charge described above, it is not altogether clear that there are significant dynamic efficiency benefits to be obtained by exposing generators to a greater number of transmission charges. In contrast, as we explain in sections 4 to 6, the potential for static inefficiencies to arise from the deeper connection, AoB and SPD charges is obvious.

3.7 Distinction between EDBs and major industrials

202. The Options Paper states that the AoB and residual charges levied upon load should be designed so as to limit distortion in the use of the grid. In both cases, a ‘capacity’ based charge is suggested. For EDBs, the proposal is to levy the charge based on deemed capacity – calculated as the sum on the nominal capacities of the active ICPs in their network areas.¹¹⁹ For major industrial customers, the allocation is instead based on their AMDs. One reason offered for this distinction is that:¹²⁰

‘...the capacity of some direct connect customers’ connections substantially exceeds their demand for transmission services, and so a reasonable proxy for their connection capacity requirements is AMD.’

203. The Options Paper states that charging major industrials based on their actual capacity may consequently incentivise them to reconfigure their assets to limit their exposure to the charge.¹²¹ It is also states that a peak demand allocator for EDBs might cause them to suppress load in an inefficient way. An ICP-based capacity

¹¹⁸ Where there is excess generation at or near a constrained node, congestion gives rise to the risk of a generator being ‘constrained off’ at inopportune times until the constraint eases. Likewise, if a generation node is distant from load centres a generator may incur significant transmission losses. In both cases, there are corresponding detriments to its operating profitability.

¹¹⁹ Options Paper, §6.79 and §6.102.

¹²⁰ Options Paper, §6.102(b).

¹²¹ Options Paper, §6.80. However, the EA also notes that any customer that was considering doing so might be extended a prudent discount to avoid this outcome if the reconfiguration would be inefficient.

charge would consequently ‘broaden the base’ across which the charge is levied, thereby reducing such distortions. Specifically, the Options Paper states that:¹²²

‘Charging on a capacity basis would ‘spread the cost across all load parties that use the grid rather than just those using it during peak times, as under the current RCPD charges. This should broaden the base upon which the charge is levied, which would lower its rate, and reduce distortions from the charge.’

204. The net effect of applying different parameters to these parties is to shift a much larger proportion of the AoB and residual charges to EDBs and, conversely, to reduce the prices to direct connect customers. For example, more than 97% of the \$355m estimated residual charge is allocated to EDBs.¹²³ This is a substantial reallocation and, in our opinion; the Options Paper does not provide a convincing explanation for the difference in approach that underlies it.
205. First, although it is true that the capacity of some direct connect customers’ connections significantly exceeds their AMD, this is also likely to be true of EDBs. A significant number of EDBs have an AMD that is less than 20% of the nominal capacity of their installed ICPs (and in some cases less than 10%).¹²⁴ In other words, the capacity of many *EDB*’s connections *also* substantially exceeds their demand for transmission services. This therefore does not represent a distinguishing factor that would warrant the application of different charging parameters.
206. Second, although EDBs might inefficiently suppress load if the charge was allocated based on AMD, this could be avoided by allocating the charge based on contributions to *coincident* peak demand – either in the ‘area of benefit’ or across a broader region. Much like the existing RCPD charge in the LNI and LSI (and soon to be the USI and UNI), this contribution could be measured across a large number of peaks (say, 100 or more) to remove parties’ incentives and ability to inefficiently shift or suppress load. This would also give Transpower the flexibility to reduce the number of periods in the future if regions began to experience congestion (see section 2.1).
207. Third, just as major industrial customers could conceivably reconfigure their assets to limit their exposure to an ICP-based charge, so too could EDBs. In particular, the charging parameter may create an incentive for EDBs – especially those facing significant transmission charge increases – to inefficiently establish micro-grids to reduce their numbers of ICPs and, in turn, the level of AoB and residual charges they must pay.

¹²² Options Paper, §6.97.

¹²³ EDBs estimated total installed capacity is 47,044MW and major industrial’s cumulative AMD is only 1,252MW, and so EDBs are allocated 97.4% of the 48,297MW total capacity ($47,044 \div [47,044 + 1,252]$).

¹²⁴ This is based on confidential information that has been provided to us by Transpower.

208. For those reasons, we do not consider that the Options Paper has provided a strong rationale for the striking reallocation of sunk costs – and attendant price effects – that would result from the proposed application of different parameters to EDBs and major users under the AoB and residual charges. In our opinion, in the absence of a compelling efficiency justification (which has not been offered), there would seem to be no obvious reason for differentiating between these two categories of offtake customers in this way when there is the option of retaining something similar to the existing RCPD-based charge.

3.8 Summary

209. There are a number of significant overarching problems that affect all of the alternative pricing methodologies that have been proposed in the Options Paper to some extent. These general shortcomings are as follows:

- there is an overall lack of precision surrounding the interpretation and application of key concepts such as ‘beneficiaries’ and ‘market-like’:
 - the approaches to identifying and charging beneficiaries differ substantially across charges – especially across the AoB and SPD charges;
 - the deeper connection is characterised as ‘market-like’ when it is not (see further discussion in section 4.1.2); and
 - the methodologies repeatedly rely upon relatively arbitrary assumptions to give effect to these loosely defined concepts;
- there are also numerous more specific inconsistencies between:
 - the problems that has been defined (whether valid or not) with the status quo and the reform options that have been proposed;
 - the approach taken to one charge (e.g., the deeper connection charge) and the approach to another (e.g., the AoB charge); and
 - the approaches taken within the same charge, i.e., the way in which a charge is allocated to different customers;
- the proposed sequencing of the charges is unworkable, i.e., it is not feasible to prioritise the deeper connection charge over the AoB charge, since:
 - it cannot be applied *ex ante* to assets not yet built since the *actual* load flow data would not be available – it would instead be necessary to use forecasts, which would create insuperable problems;
 - assets may transition in and out of the deeper connection charging framework over time, leading to highly volatile charges and compromising parties’ ability to engage constructively in new investment processes; and

- there would be no satisfactory way to reapply AoB charges to a narrower group of assets if certain assets within a broader group (such as the NIGU lines or the Wairakei Ring) are reclassified as deeper connection;
- insufficient attention is given to practical factors such as economies of scale that will have influenced investment outcomes, which is problematic since:
 - the assets to which deeper connection and AoB charges are applied may be larger and more expensive than those that parties would have opted for if given the choice (see further discussion in section 4.2.1); and
 - allocating 100% of the costs of those assets to the identified parties may cause them to lobby for smaller, less efficient investments and to change their behaviour in undesirable ways to reduce their charges;
- if implemented, the proposed options would result in an exceedingly complex TPM, which raises questions about:
 - whether Transpower can design, implement and administer the methodology in a cost effective manner; and
 - whether parties will be able to fully understand the methodology in order to engage constructively in new investment processes;
- the options would expose generators to significantly more transmission charges, which may deliver few (if any) efficiency benefits, but may result in significant static efficiency costs.

210. These deficiencies mean that the proposed options lack cohesion and contain many arbitrary assumptions that have a large impact upon the allocation of charges. In our opinion, for these reasons alone, they should not be countenanced as currently designed. Moreover, as we explain in the following sections, there are further more specific problems with the individual charges.

4 Deeper Connection Charge

211. The ‘deeper’ connection charge extends the definition of deep connection assets further into the grid, to cover all assets that are used predominantly by a small number of parties that are not already classified as connection assets. We examine the perceived advantages and potential drawbacks of the proposed charge below.

4.1 Perceived advantages

212. The Options Paper identifies two key advantages with the deeper connection charge. The first is that it represents a logical extension of the philosophy underpinning the existing deep connection charging framework. The second is that it is a ‘market-like’ charge that will better promote workably competitive market outcomes. We explore each of these advantages in turn below.

4.1.1 Extension of the existing connection charge

213. The principal reason for favouring the *current* deep connection charge was to encourage connecting parties to make efficient locational decisions for their plant, by trading off the additional costs of locating at various points with the additional costs of connection.¹²⁵ The rationale was that, if a significant portion of the costs of connecting, say, a new generator is spread over all users (or on load), then it may pay less attention to where it connects and do so inefficiently.
214. The existing charge has essentially been ‘as deep as practicable’, and has provided the strongest signal possible hitherto. The proposed *deeper* connection charge might therefore in some sense be characterised as an extension of the current framework. In principle,¹²⁶ the advances in load flow tracing may enable connecting parties to be faced with an even more comprehensive account of the costs of connecting – at least insofar as new investments are concerned.
215. This may serve to reduce the ‘wedge’ that exists between the charges levied on particular customers and their private benefits – a divergence that may grow over time under the current TPM. For example, as we explained above, if this discrepancy grows,¹²⁷ then it is conceivable that this may result in distortions over

¹²⁵ Electricity Commission, *The Commission’s Statement of Reasons in relation to the Proposed Guidelines for Transpower’s Pricing Methodology*, 18 February 2005, §98-99.

¹²⁶ As we explain in more detail in the following section, it is questionable whether the load flow tracing methodology achieves this outcome *in practice*, i.e., in some (perhaps many) circumstances it will not identify and levy charges upon the parties that have ‘caused’ an investment or benefited from it.

¹²⁷ In part because the costs of ‘deeper connection assets’ are socialised via the interconnection charge.

the long-term.¹²⁸ To this end, the charge might also be perceived as ‘fairer’ since, like the connection charge, it seeks to sheet home to users the costs of the grid assets that they are deemed to be using.

216. In our opinion, the deeper connection charge does have some intuitive appeal in these respects. However, there are also some important differences between both the design and coverage of the two charges. In particular, as we explain below, the philosophy underpinning the connection charge (i.e., charging parties for the assets they use – which are often built specifically for them) does not necessarily translate so readily to deeper connection assets.

4.1.2 A ‘market-like’ charge

217. The Options Paper states that a further advantage of the deeper connection charge is that it is ‘market-like’. Specifically, it states that the charge identifies situations in which, in the absence of a regulator, the parties involved could have come together to negotiate an efficient contract for investment.¹²⁹ This is said to promote workably competitive market outcomes and, in turn, efficient investment and operation.¹³⁰ We disagree with this characterisation.
218. The contention that the charge is ‘market-like’ is predicated on the belief that the charging framework will capture situations in which, in the absence of the regulator, the parties upon whom the charges are levied would have:
- come together to negotiate a commercial agreement to build the deeper connection asset in question; and
 - faced the *same net cost* as they are being exposed to via the deeper connection charge (at least, that is the clear implication).
219. Neither of these assumptions is correct. In reality, the application and level of the deeper connection charge may bear no resemblance to a plausible (hypothetical) competitive market outcome. We elaborate below.

4.1.2.1 *The application of the charge is arbitrary*

220. As we set out in our first report,¹³¹ it should be remembered that, in the early 1990s, it was expected that ‘market-based’ investment would become a central feature of

¹²⁸ To reiterate, whether such distortions are likely in practice is ultimately an empirical question that will need to be explored in more detail in the second Issues Paper.

¹²⁹ Companion Paper, §3.6.

¹³⁰ Companion Paper, §3.7.

¹³¹ The history of market-driven transmission investments in New Zealand is recapped in Appendix A of: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013. See also: Green et al,

the market, i.e., that private parties would contract to build interconnection assets. It did not.¹³² Instead, the experiment failed because insufficient attention was given to the impracticability of applying market-based principles to shared grid infrastructure. The practical challenges include:¹³³

- once built, transmission lines tend to eliminate congestion, which may render any physical or financial transmission rights worthless (at least for a time) and undermine the incentives parties have to build them;
- parties have strong incentives to ‘free ride’, e.g., if a generator stands to benefit from congestion being eliminated, it may be better off waiting and hoping that someone else invests first (creating a potential stalemate); and
- the fact that there is often more than private benefits at stake, e.g., increased transmission can reduce market power and increase network reliability, and there are also valid economic and national security reasons to ‘err on the side of caution’ and overbuild (and earlier) than underbuild (or build late), given the substantial asymmetric risk.

221. This market failure manifested primarily in underinvestment and led, ultimately, to the introduction of the TPM and the associated administrative processes for approving new investments. In other words, the thought experiment being conducted in the Options Paper rests on a false premise. The presence of a regulator does not *prevent* market-based investments from occurring. Rather, it allows investments to occur that otherwise *would not happen* – and for them to be sized and timed appropriately.

222. This is especially likely to be the case for reliability investments in the core grid – a number of which have been earmarked for deep connection charges. Under Schedule 12.2 of the *Electricity Industry Participation Code*, a reliability investment would be approved if it was necessary to meet applicable grid reliability standards and maximised the expected net benefit compared with alternative projects, with the proviso that the expected net benefit *could be negative*.¹³⁴

223. The effect of this proviso is that the cost of a reliability investment might well exceed the expected private benefits (unlike for an ‘economic investment’). In these

New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group, 28 August 2009, section 2.2.

¹³² To date, user-driven transmission investment has been limited to connection assets, where the ‘users’ and ‘beneficiaries’ of assets can be more readily identified, and where the practical complications described below do not represent such an obstacle.

¹³³ See: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group, 28 August 2009, pp.9-10.*

¹³⁴ See: CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower, March 2014, section 2.3.2.*

circumstances, even if the practical challenges set out above could be overcome, the assets in question would still not have been built in a hypothetical market setting since there would be no individual parties that derived sufficient private benefits to warrant outlaying those investment costs.

224. For those reasons, there are arguably *no circumstances* in which the parties in question could have come together in the absence of a regulator to build the deeper connection assets at issue. Those assets may instead simply not be there in this ‘counterfactual’. In this sense, the Options Paper is trying to identify what could amount to an empty set. Moreover, the scenarios that the proposed criteria will actually capture are fundamentally arbitrary.
225. For example, there is no reasonable basis to conclude that a generator with, say, a 75% share of load flows across a node would be able reach a commercial agreement with a handful of smaller generators, but that three, say, equally sized generators (with a 33.3% share of load flows) would not. Nevertheless, under the current design, the former scenario will result in generators paying a deep connection charge but the latter will not.
226. The logic underpinning that distinction – and other similar situations that will inevitably arise – is unclear. If the former is considered to be a ‘market-like’ scenario (rightly or wrongly) that warrants the application of the charge – why not the latter? In short, the basic economic rationale for the approach is unsound. One simply cannot conclude that the charge will identify situations where assets could have been financed through commercial negotiation. It will not.

4.1.2.2 *The charges themselves are not market-like*

227. Even if the HHI thresholds did capture all of the situations in which parties could have reached a commercial outcome (which they do not), that would not mean that the resulting *prices* were ‘market-like’. There are a number of reasons why the deeper connection charges that would be levied upon particular parties might bear little resemblance to the net costs that they would have incurred in a hypothetical commercial negotiation.
228. In a regulatory setting, many considerations influence transmission investment decisions, including strong economies of scale. As we set out in section 4.2, once land has been purchased and the pylons built, there is not much difference in cost between low and high capacity lines – so larger lines tend to be built.¹³⁵ The assets identified as ‘deep connection assets’ will inevitably – and quite rightly – have been built with these practical considerations in mind.

¹³⁵ Recall also that investments can offer broad benefits, such as reducing market power and increasing network reliability. There may also be valid national security interests to ‘err on the side of caution’ by building ‘bigger and earlier’ than ‘too small or too late’.

229. In contrast, assuming that private parties could feasibly undertake a market driven investment (which, as we explained above, is doubtful), they may be indifferent to considerations such as mitigating market power and national security interests. And they will only care about economies of scale if they expect that they will be able to use that additional capacity themselves, or if they can *sell it to other parties at a profit* (since they will have those property rights). It follows that the parties to such a negotiation will either:
- build an asset that is sized to meet only *their own* requirements, i.e., if they do not think that they will be able to sell any surplus capacity then there is no benefit from incurring the higher costs of building it; or
 - take advantage of economies of scale to build a deeper connection asset that is larger than needed to meet their own forecast requirements so that they can *sell that spare capacity to other users at a profit*.¹³⁶
230. In other words, the investments that have arisen from the existing regulatory framework may be *quite different* from those that might otherwise have resulted from *market* processes (assuming market-driven investments are even possible). Furthermore, the *net cost* that those parties would have faced in those hypothetical commercial settings may have been *considerably lower* than the deeper connection charges that they would face under the proposed framework.
231. Nevertheless, the proposed methodology assumes unrealistically that the parties would have built the *same assets* – even though they may greatly exceed their own requirements and would have entailed greater costs – and then allowed other parties to use them *for free*. Indeed, there are a number of different circumstances in which certain parties would be required to pay deeper connection charges, when other parties that also ‘use’ assets to some extent would pay nothing. For example, this could happen when:
- the ‘supply-side’ HHI threshold is above 5,000 but the ‘demand-side’ HHI threshold is below 4,000 but still positive (or vice versa); and/or
 - there may be smaller users who do not meet the ‘3% threshold’¹³⁷ at a node who are consequently not required to pay any deeper connection charges.
232. In the case of the former, all offtake customers using an asset would be doing so without paying for it and, in the latter, smaller users would be getting a ‘free ride’, as

¹³⁶ Bearing in mind that once built, transmission lines tend to eliminate congestion, which may render any physical or financial transmission rights worthless (at least for a time), undermining the incentives that parties have to build them in the first place.

¹³⁷ A node is deemed to be connected to a particular deep connection asset only if the node’s mean flow share for the asset is at least 3% of its AMD (for a load node) or its AMI (for a generation node). *See*: Companion Paper, §A.41.

it were. These do not represent plausible ‘market-like’ outcomes. Rather, if the parties upon which charges are levied had privately invested in that capacity – and owned either the physical or financial rights to it – they would naturally be expected to charge *anyone else* who uses it. As we noted above, this would reduce the ‘net cost’ of that capacity below the levels implied by the deeper connection charges.

233. It is also important to remember that just because load flow tracing reveals that a party is ‘using’ a link, that does not necessarily mean that it derives substantial private benefits from its existence. Under Kirchoff’s laws, electricity flows down the path of least resistance – but it does not necessarily *cease* to flow if any particular path is taken away. If a deeper connection asset is removed, electricity may simply traverse a more circuitous route. This may be of relatively little consequence to a party that was previously ‘using’ the shorter route.
234. By way of analogy, imagine that a person drives down the same road to and from his place of work every day and that he is one of only a small number of people that does so. It does not necessarily follow that he would be willing to pay a significant sum to maintain that road. The amount he would be willing to pay would depend upon how inconvenient it would be for him if the road was unavailable. If another road runs parallel and only takes a few more minutes to travel, then his willingness to pay might be very low.
235. For the same reason, just because load flow tracing reveals parties to be ‘using’ a particular asset does not mean that they would have been prepared to pay to build that asset in a market setting. If the parties had relatively uncongested ‘parallel routes’ at their disposal, they may not have been willing to build anything at all or, alternatively, they might only have been prepared to construct something significantly smaller and less expensive (consistent with what we described earlier).
236. The application of the ‘3% threshold’ in conjunction with the AMD/AMI allocation increases further the probability that the charges levied upon parties will overstate the benefits that they obtain from assets. Specifically, a party may be allocated a large percentage of an asset’s total cost, even though it accounts for only a modest percentage of load flows. The ‘Clyde to Roxburgh’ link –is illustrative. The load flow and HHI shares are as follows:¹³⁸

Customer	Flow	Flow Share	HHI calculation
Contact	114.40	75.1%	0.5640
Genesis	2.46	1.6%	0.0003
Meridian	32.85	21.6%	0.0467
Total	150.754	98.3%	0.6109

¹³⁸ Electricity Authority, *Transmission Pricing Methodology (TPM) Review, TPM options working paper, Workshops, July 2015*, slide 18.

237. The table reveals that the supply-side HHI threshold is met (i.e., $75.1\%^2 + 1.6\%^2 + 21.6\%^2 = 6,109$). However, the demand-side HHI is only 3,524, and so the required revenue is recovered from generation only. Given that Contact accounts for $\frac{3}{4}$ of the flows on the line, one might consequently expect that, in a commercial negotiation, it would assume responsibility for an equivalent proportion of the costs. However, because charges are allocated based on the generator's respective AMIs at their points of connection, the allocation of charges is quite different.
238. There are three nodes above the 3% threshold: Clyde with AMI of 430MW (Contact), Roxburgh with AMI of 330 MW (Contact) and Waitaki with AMI of 90MW (Meridian). As a consequence, the \$2.19m (approximate) annual revenue requirement is recovered through deep connection charges in the following way:
- Contact pays $760 \text{ MW} \div 850 \text{ MW} = 89.4\% \times \$2.196 \text{ million} = \1.96m ; and
 - Meridian pays $90 \text{ MW} \div 850 \text{ MW} = 10.6\% \times \$2.196 \text{ million} = \0.23m .
239. In other words, despite accounting for only 75% of the load flows, Contact would be required to pay around 90% of the deeper connection charges. Similarly, although Meridian accounts for 22% of those flows, it would pay around 10% of those costs. Furthermore, neither off-take customers nor Genesis would pay *any* deep connection charges, despite also 'using' the assets due to the application of the HHI and 3% thresholds, respectively. In our opinion, it is implausible that such an allocation would emerge from a hypothetical commercial negotiation.
240. For all of these reasons, it is simply not accurate to characterise the deeper connection charge as 'market-like'. It is not. It is also arguably not an 'exacerbators-' or 'beneficiaries-pay' charge.¹³⁹ The methodology will neither identify the situations in which it would have been plausible for parties to reach a commercial agreement, nor replicate the net costs that they would have faced (and we do not think it ever can¹⁴⁰). This therefore does not represent an advantage.
241. Moreover, the charge has a number of other significant drawbacks. In particular, its design has the potential to give rise to significant dynamic and static inefficiencies. As we explained below, it may cause the parties that are required to pay those charges to lobby for inefficient investments, i.e., for smaller assets or for delays. In addition, it may cause parties to change their behaviour in inefficient ways in order to avoid those costs.

¹³⁹ For the reasons set out above, the way the charge has been designed means that not all exacerbators or beneficiaries will necessarily be charged and, conversely, it is possible that some of the parties that are charged had very little to do with the line being needed (i.e., did not 'cause' the need for the investment) and/or derive few benefits from it.

¹⁴⁰ As we explained above, there are likely to be too many practical obstacles (many of which we set out above) for market-based investment in interconnected assets to be achievable in practice.

4.2 Potential challenges

242. There are a number of potential challenges that would need to be overcome before one could be confident that the proposed deeper connection charge would not compromise static and dynamic efficiency. Some of these are ‘common’ to other charging options, and were described in section 3. By way of brief recap:

- The definition of ‘beneficiaries’ differs substantially from the approach taken under the AoB and SPD charges. Charges to generators are also levied based on AMI, whereas MWh is the proposed allocator for AoB charges.
- The sequence of charges means that assets may transition in and out of the deeper connection charging framework over time as grid usage patterns change. This may lead to undesirable price volatility and it may adversely affect the new investment process.
- Because prices are linked to the net book values of the assets, they will be highest immediately after an investment and lowest just before it is replaced. This is the opposite of what efficient transmission pricing requires.
- Economies of scale will often mean that it is more efficient to build deeper connection assets that are bigger than are needed to meet the near-term requirement of today’s users. Seeking to recover 100% of those costs from a sub-set of current users may cause them to lobby for inefficiently small investments and to change their behaviour to avoid the charge.
- The charge is highly complex. The load flow tracing underlying the approach is not something that can be easily replicated, much less forecast, by many participants. This would undermine further their ability to engage constructively in new investment processes.

243. However, there are also additional, more specific challenges that are unique to the deeper connection charge that arise from its detailed design. As we explain below, some of these potential problems might not be all that significant in practice – or could be relatively easy to address. Others may be more difficult to overcome.

4.2.1 Distortions to behaviour from AMI and AMD charges

244. Whenever a ‘line’ is drawn that requires parties to pay more or less transmission charges – in this case potentially considerably more – depending upon ‘which side of the line’ they fall, potential distortions can be created. Indeed, the Options Paper acknowledges – quite rightly – that one potential disadvantage of the deeper connection charge is that it may incentivise customers to alter their behaviour to reduce its effect upon them. We agree. Some potential examples include:

- load might seek to reduce their deep connection charges by sponsoring inefficient amounts of embedded generation or demand side management (DSM) initiatives so as to reduce their AMD; and

- generators facing a substantial deep connection charges may similarly seek to reduce them by strategically withholding their capacity to reduce their AMI or to embed so as to hide behind load.

245. In terms of the latter, we noted in section 3.6.1 that this is same inefficient conduct that is being caused currently by the HAMI-based charging parameter applied to the HVDC charge. The EA and Transpower have both acknowledged that this is a material problem and a proposal to switch the HVDC parameter to an average MWh charge for South Island generators is currently being considered (and appears likely to be adopted).¹⁴¹ In this sense, the current design of the deeper connection charge would seem to give rise to the potential for ‘history to repeat’.

246. Moreover, the potential magnitude of the deeper connection charges in question – which, in some cases, are quite large – means that the incentives for parties to engage in this behaviour might be quite strong. It is also not easy to avoid these incentives by using different allocation mechanisms, e.g., switching to capacity or MWh charges. These will each entail their own drawbacks (we explain some of the specific problems with MWh charges when we consider the AoB charge which, curiously, employs this different approach).

4.2.2 Consolidation, entry and exit

247. A further potential problem with the proposed delineation of deeper connection assets is that the charging arrangements may result in large price changes as customers connect and disconnect. This may have a number of adverse effects, such as encouraging disaggregation, discouraging efficient consolidation, and causing ‘cascading’ exits, where one disconnection leads to another. The Options Paper suggests several ways in which these impacts might be mitigated:

- it is suggested that firms could be discouraged from disaggregating by ignoring such effects upon the HHI, i.e., by continuing to treat them as a single entity;¹⁴²
- it is proposed that efficient mergers might still be encouraged by ‘adopting a lower HHI threshold’;¹⁴³ and
- it is claimed that the incentive for other parties to disconnect if a first party exits can be mitigated through calculating the HHI over a five-year period, with the charges then retained for the following five years.

¹⁴¹ See: Electricity Authority, *HVDC component of Transpower’s proposed variation to the Transmission Pricing Methodology Consultation Paper*, 23 June 2015.

¹⁴² Companion Paper, §4.23(b)(iii).

¹⁴³ Companion Paper, §6.5(c).

248. In our opinion, the proposed treatment of disaggregated companies (that remain interconnected bodies corporate) seems sensible and should serve to prevent such conduct. However, the other suggested solutions are problematic. First, although reducing the HHI threshold could certainly avoid discouraging parties to merge (since they are more likely to already be paying deeper connection charges), we do not agree that this is the most effective solution.
249. The first difficulty is that the effectiveness of the step will vary from case to case depending upon the merging parties and the HHI threshold selected. In some cases, a reduced HHI will make little if any difference. Of course, the lower the HHI threshold, the less likely it is that efficient mergers will be discouraged. However, in our view, selecting a very low threshold to guard against this possibility would risk compounding all of the inefficiencies we described in sections 4.1.2 and 4.2.1.
250. The suggested approach is also difficult to reconcile with the proposed treatment of *disaggregating* companies. The recommended remedy in that case was to measure the HHI as if the disaggregation had not occurred. This begs the question: why not do the same for mergers, i.e., continue to use the pre-merger HHI – at least for a period? This approach would seem to be more consistent and would remove the need to reduce the threshold, which would create other problems.
251. Second, measuring HHIs over a 5-year window and applying the charges for the ensuing 5 years does not necessarily address the problems arising from firms entering and exiting and it may create other intertemporal distortions. In some cases that smoothing could well serve to reduce the impact of exits upon remaining parties. For example, suppose that a customer disconnects, and this increases the HHI *at that point in time* from below 4,000 to above 5,000.
252. If that exits occurs at the ‘back end’ of the 5-year assessment period, it may not be sufficiently impactful to increase the relevant 5-year average HHI above 5,000. If that is the case, the remaining parties *may* not face an immediate substantial increase in costs due to the asset being classified as a deep connection asset.¹⁴⁴ However, in other circumstances, the 5-year averaging will do little to suppress large price increases from such customer movements.
253. For example, if a party disconnects and the relevant HHI was *already* above 5,000, then averaging will *make no difference*. Specifically, it will not prevent the remaining parties from being allocated a larger share of the sunk costs of those assets (since the charge is designed to recover 100% of the annual revenue requirement). The resulting increases in prices may make it more likely that these remaining parties may *also* disconnect, creating a cascading effect.

¹⁴⁴

Unless that increase simply manifests through higher AoB charges, which is possible.

254. The Options Paper acknowledges that its *AoB charge* could result in prices that exceed the incremental private benefits of some participants, which could distort their behaviour, including to the extent that they potentially disconnect.¹⁴⁵ It has suggested that such situations be dealt with through the prudent discount policy. In our opinion, this scenario is equally – if not more – likely in respect of the deeper connection charge.
255. Although application of the prudent discount framework *might* be able to address problems relating to *exit*, it cannot address some of the other potential distortions surrounding *new entry*. For example, suppose that a new generator connects and this reduces the supply-side HHI from above 5,000 to below 4,000. If deeper connection charges were calculated based on that ‘snapshot’, then no such charges would be applied to anyone.
256. However, application of the 5-year averaging window may again give rise to a different outcome. For example, if the generator connects toward the end of the averaging period, its entry may not be sufficiently impactful to reduce the 5-year average below 4,000. In those circumstances:
- for the remainder of the current 5-year pricing period, the new generator would not be paying deeper connection charges – even though others may be;¹⁴⁶ and
 - in the following period the new generator – and other users – would be paying deeper connection charges, even though the *current* HHI was below 4,000.
257. This may distort wholesale market competition in the region, since there may be a period where the new generator is not paying deep connection charges, but other generators are. It may also effect the investment decision itself. Although it may not effect *where* the new generator locates¹⁴⁷ it may affect *when* it builds. For example, it may time its entry so as to minimise its exposure to deeper connection charges. These problems are not readily addressable through the prudent discount policy.
258. Finally, it is worth highlighting that the matters that we have set out above are simply *potential* problems. If the assets in question exhibit reasonably stable HHIs over time – and there is a strong expectation that they would continue to do so in the future – then the difficulties described above may not be germane to the choice of pricing option. As with many of the other issues that we have raised in this report this is, once again, ultimately an empirical question.

¹⁴⁵ Options Paper, §6.81.

¹⁴⁶ Under the proposal it *might* be required to pay AoB charges, but these may be considerably less than the deeper connection charges that it might otherwise face.

¹⁴⁷ As we explained in section 3.6, locational investment decisions tend not to be determined by transmission prices, but instead factors like the availability of fuel sources and the presence of transmission constraints.

4.2.3 Rationale for exclusion of HVDC charge

259. Based on the EA's published model results the HVDC link meets the supply-side HHI threshold for deeper connection charges, but does not meet the demand-side HHI. Nonetheless, the Options Paper states that the HVDC link will *not* be treated as a deeper connection asset. The rationale offered for this exclusion is that:¹⁴⁸

'Treating the HVDC link as deeper connection would be inconsistent with the intention of the deeper connection charge, which is to extend the effective definition of connection deeper into the grid. The HVDC link is not an asset required to connect a party to the grid. Rather, it is an asset that is used to connect the North Island and South Island alternating current (AC) grids.'

260. We find this logic difficult to follow. We do not see the distinction that the Options Paper is seeking to draw between the HVDC link and assets such as the NIGU and NAaN lines. Neither of these recent upgrades is 'required' to connect a party to the grid – they are, after all, expanding a network that already exists. They are links that, like the HVDC, facilitate the flow of energy from one part of the interconnected network to another.

261. If anything, the HVDC link bears a closer resemblance to a 'connection' asset than the other assets the Options Paper identifies, because it is actually joining two parts of the network that would, in its absence, be physically separate. For those reasons, the *physical characteristics* of the HVDC do not, in our view, set it apart from other assets to which the charge will be applied. In short, the rationale that has been presented for excluding the HVDC link is not sound.

262. That is not to say that there are no good reasons to eschew applying deeper connection charges to the HVDC link. *There are*. The ostensible reluctance to include the HVDC link in the deeper connection charging framework may stem from the fact that, based on the current load flow analysis (under which the supply-side HHI is met, but the demand-side HHI is not), only certain generators would pay for 100% of the costs of the link when, in fact:

- the link it is, in truth, a 'shared asset' that delivers a much wider array of benefits to myriad parties – as the Options Paper recognises,¹⁴⁹ and
- the link was built so as to cater for future demand growth, which means that today's users do not necessarily benefit from that spare capacity right now.

263. Seeking to recover 100% of the costs from this sub-set of generators may therefore cause them to respond inefficiently. In particular, they could strategically withhold

¹⁴⁸ Companion Paper, §4.20.

¹⁴⁹ Table 6 of the Options Paper sets out estimates of the extent to which different customer groups benefit from the HVDC link.

supply in order to reduce their AMIs and their attendant exposure to charge.¹⁵⁰ These *are* potentially legitimate concerns. However, as we explained in sections 3.4 and 4.1.2, they are *not unique* to the HVDC link – they potentially affect *all of the assets* that have been earmarked for deep connection charges.

264. Indeed, just as the HVDC link was sized to cater for future growth and to deliver wider economic benefits, so too were investments such as the NIGU and NAaN lines. It follows that if the adverse effects described above are sufficiently serious to warrant the omission of the HVDC link from the charging framework, the logical corollary is that *all assets* should be excluded from the charge – at least as it is currently designed.
265. If the deeper connection charge was nonetheless retained in its current form – despite the myriad shortcomings described above – there are other potential reasons to exclude the HVDC link from its scope. From a practical perspective, HVDC and interconnection assets *are* differentiated and treated separately in the regulatory arrangements administered by the Commission, i.e., there are distinct revenue streams and performance measures. In this sense, they could be said to be distinguishable because they are *already distinguished*.

4.3 Summary

266. The deeper connection charge could be characterised as a logical extension of the existing connection charging framework. However, it is not correct to describe the charge as ‘market-like’. This characterisation is predicated on the belief that the framework will capture situations in which, in the absence of a regulator, the parties upon whom the charges are levied would have:
 - come together to negotiate a commercial agreement to build the deeper connection assets in question; and
 - faced the same net cost as they are being exposed to via the deeper connection charge (at least, that is the implication of the methodology).
267. Neither of these assumptions is correct. The application and level of the deeper connection charge may bear no resemblance whatsoever to a plausible (hypothetical) competitive market outcome, because:
 - the charge will *not* capture all situations in which a hypothetical commercial negotiation would have been possible in the absence of a regulator, since:

¹⁵⁰ As we explained above, the existing HVDC charge has given rise to precisely this inefficient strategic withholding of supply by South Island generators. This problem would be mitigated significantly if Transpower’s proposal to switch to an average MWh charge is implemented. However, the Options Paper proposed to levy deeper connection charges to generators based on AMI, so the problem would resurface if the charge is applied to the HVDC link.

- in truth, this may be an empty set – in the absence of a regulator and an investment framework, these assets may not have been built at all; and
- in any event, the application of the charge is arbitrary, i.e., there will often be no good reason why it is applied in one scenario but not in another;
- in most cases, the parties upon which deeper connection charges are being levied would be facing a *lower* net cost in a hypothetical market setting, since:
 - they might have built something smaller and less expensive to meet just their own needs, i.e., without spare capacity;
 - if they did build an asset with surplus capacity, they would *sell* it to other users to reduce their net costs, i.e., there would be no free riding; and
 - there would be unlikely to be any large discrepancies between the extent to which a party uses an asset and the net cost they faced in doing so.

268. Seeking to recover 100% of the costs of deeper connection assets from the identified set of users (who may only be a small sub-set of *all* users) may consequently risk giving rise to both dynamic and static inefficiencies; namely:

- the parties may have an incentive to lobby for inefficiently small investments or for delays to expansions, both of which may reduce net market benefits; and
- they may seek to change their behaviour in sub-optimal ways to reduce their exposure to the charge, for example:
 - load might seek to reduce their charges by sponsoring inefficient amounts of embedding generation or DSM to reduce their AMD; and
 - generators may seek to reduce their charges by strategically withholding their capacity to reduce their AMI, or embedding so as to hide behind load.

269. In addition to the overarching problems that we described in section 3 (and which we do not repeat here), the deeper connection charge also exhibits the following more specific design problems:

- it may result in large price changes as new customers connect and existing customers disconnect from the transmission network; and
- averaging the HHI calculation over a five year period may give rise to both static and dynamic efficiencies, for example:
 - there may be periods when newly connected generators are not paying the charges, but others are, which could distort competition; and
 - generators may time their entries so as to minimise exposure to deeper connection charges, which may cause cheaper generation to be delayed.

270. Finally, we note that the rationale that has been presented for omitting the HVDC link from the deep connection charging framework is not sound. There are good



reasons to exclude the link but, in many cases, they apply equally to *all* of the assets earmarked for the charge. The appropriate course of action is therefore to not apply the charge *to any assets* – at least not as currently designed.

5 Area of Benefit Charge

271. The AoB charge expands the ‘GIT-based’ method proposed in the Beneficiaries Pay Options Paper by applying it not only to ‘reliability’ investments, but also to ‘economic’ investments. Two potential variants are proposed:¹⁵¹
- a ‘static’ approach, with charges being allocated to the beneficiaries identified in the original investment approval document; and
 - a ‘dynamic’ approach, with the potential for a different set of parties to be charged as the profile of beneficiaries changes over time.
272. Limiting criteria are also applied, i.e., the charge will not apply to investments below certain thresholds, or built before particular points in time.¹⁵² We examine the perceived advantages and potential drawbacks of the charge below.

5.1 Perceived advantages

273. The principal perceived advantage of the AoB charge is that it may better align the charges that parties pay with the private benefits that they obtain from investments. This would go some way to addressing the overarching problem that the EA appears to have with the existing TPM – namely, its belief that parties who do not benefit significantly from investments are being forced to contribute too much to their costs and, conversely, that those parties who do benefit are not paying enough.
274. As we explained above, this entails notions of both efficiency and equity. The potential efficiency benefits stem from reducing the ‘wedge’ that exists between the charges levied on particular customers and their private benefits – a divergence that could grow over time under the current TPM and may give rise to distortions.¹⁵³ The charge might also be said to be ‘fairer’ in a subjective sense.
275. Indeed, the proposition that parties that benefit from investments should pay for them and those that do not should not clearly has intuitive appeal. However, as we have explained above (and reiterate below), that is not always *efficient* – especially when it involves reallocating the sunk costs of past investments. It also presumes that the beneficiaries can be accurately identified and their private benefits assessed. As we explain below, none of these assumptions hold in practice.

¹⁵¹ Options Paper, §6.68.

¹⁵² Options Paper, §6.59.

¹⁵³ The Options Paper also states that charging beneficiaries will assist in the discovery of efficient investments by facilitating superior consultation and decisions. However, for the reasons that we set out in section 2.3, that is unlikely to be the case.

5.2 Potential challenges

276. Before one could be confident that the AoB charge would not compromise static and dynamic efficiency, it would first be necessary to address the ‘general’ problems that we set out in section 3, which also affected the deeper connection charge. To recap:

- The definition of ‘beneficiaries’ differs substantially from the approach taken under the deeper connection and SPD charges. Charges to generators are also levied based on MWh, whereas AMI is the proposed allocator for deeper connection charges. Different parameters are also applied to EDBs (total ICP capacity) and direct connect customers (AMD) without compelling justification.
- The sequence of charges again means that assets may transition between the deeper connection and AoB charging frameworks over time as usage patterns change. This may lead to undesirable price volatility and it may adversely affect the ability of parties to engage constructively in new investment processes.
- Because charges are once more linked to the net book values of the assets, they will be highest immediately after an investment and lowest just before it is replaced. This is the opposite of what efficient transmission pricing requires.
- Economies of scale will often mean that it is more efficient to build assets that are bigger than are needed to meet the near-term requirement of today’s users. Seeking to recover 100% of those costs from today’s users may cause them to lobby for inefficiently small investments and to change their behaviour in sub-optimal ways to avoid the charge.
- Because usage patterns will change over time it may be difficult to accurately identify beneficiaries under the ‘static’ approach and for parties to predict the charges they will face under the ‘dynamic’ approach. This will limit further parties’ ability to engage constructively in new investment processes.

277. There are also additional, more specific challenges that are unique to the AoB charge that arise from its design and application. As we explain below, it is not altogether clear whether there are any effective solutions to these problems – particularly the potential distortions to the wholesale market.

5.2.1 Distortions to the wholesale market from MWh charge

278. If AoB charges were to be levied upon generators in the manner envisaged in the Options Paper, this will increase the opportunity cost of generating, and may result in higher wholesale prices. As we explained in section 3.6.1, this is because if the charge is levied in proportion to MWh injection (as proposed) this is, in effect, an additional variable cost. A generator can therefore be expected to take that additional expected cost into account when formulating its wholesale bids.

279. As we noted earlier, this was one of the key reasons why a MWh was not recommended to allocate deeper connection charges.¹⁵⁴ It is consequently unclear why these problems are not raised in the discussion of the AoB charge. The proposed approach is also at odds with advice provided to the EA's predecessor by Frontier Economics during a previous review of transmission pricing. Frontier quite rightly described charges based on MWh injected or withdrawn as inefficient 'taxes' on transmission grid usage. It cautioned that:¹⁵⁵

*'If transmission charges are to be imposed in a way that diverges from least distortionary sunk cost recovery, it is important that transmission charges are **not based on usage of the transmission network, in terms of MWh injected or withdrawn from the grid.** Usage-based charges operate as a tax on usage, deterring the utilisation of sunk assets. Dynamic efficiency requires that charges influence participants generation and load investment decisions but minimise their impact on operational decisions, such as electricity consumption and generator bidding/dispatch.'* [Emphasis added and internal footnote removed]

280. The effect of a MWh charge is that some generators may be dispatched when they have a higher 'true' SRMC than others that are not called upon. That is highly undesirable.¹⁵⁶ Imagine a generator is deemed to be a beneficiary of an asset and must pay an AoB charge. When formulating its wholesale bids, it would consider its SRMC (fuel, labour costs, etc.) *and* the quantum of AoB charges it expects to pay. The latter are not 'true' marginal costs – they are *fixed sunk costs* that are *made* variable by the design of the charge. This is problematic because:

- the true SRMC of using the transmission grid are the costs of losses and constraints – which are often very low;
- imposing additional variable costs on a generator to recover costs that are fixed and sunk will cause it to factor them into its wholesale bids; and
- as a result, other generators that are, in fact, more expensive in 'true SRMC-terms' may be dispatched instead, resulting in inefficiently higher prices.

¹⁵⁴ Companion Paper, §4.26(b)(ii).

¹⁵⁵ Frontier Economics, *Theory of efficient pricing of electricity transmission services, A Report for the New Zealand Electricity Commission*, July 2009, p.19.

¹⁵⁶ To be clear, such 'taxes' do not *necessarily* reduce the efficiency of the wholesale sector if all generators' costs are more or less equally (proportionally) increased. In those circumstances, the short run marginal cost (SRMC) 'curve' would 'shift up' but its 'shape' would not be affected. However, in this instance, different generators *will* be affected differently – such that both the level and the shape of the SRMC curve will be distorted. For a more detailed description of this phenomenon, see: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, §113.

281. The situation described above represents an inefficient use of grid infrastructure. When investments are sunk and load can be served more cheaply by generators using those assets, it is efficient for the TPM to facilitate that least-cost outcome. If the pricing mechanism causes generators using certain assets to act in the manner described above, prices in the wholesale market will be higher than would otherwise be the case. This is unambiguously harmful to consumers.¹⁵⁷
282. In our opinion, it is likely to be very difficult to design the AoB charge in a way that will not create potential inefficiencies if it is levied on generators. For the reasons we set out in 3.6.1, irrespective of the charging parameter, generators are likely to have incentives to alter their behaviour to avoid the charge. For example, shifting to a peaking charge (e.g., based on AMI) may lead to generators strategically withholding capacity – as is currently the case with certain plant based in the South Island to avoid additional HVDC charges.

5.2.2 Identifying beneficiaries

283. Some of the potential inefficiencies we described above are symptomatic of a broader problem with the AoB charge as proposed. Although the charge seeks to allocate the costs of investments to the parties perceived to be benefiting, those beneficiaries will *change over time*. This means that even if the right parties have been identified in the first instance and the correct initial charges set (which, for the reasons we set out in section 4.3, may not be the case), things may change. New customers may connect, others may disconnect and grid usage patterns may evolve.
284. In our opinion, these factors mean that, in the absence of reciprocal physical capacity or financial transmission rights, the ‘static’ approach would be impossible to implement. Shifting to a ‘dynamic’ approach mitigates these problems to *some* extent, since it allows beneficiaries to be periodically updated. However, that does not address the distortions that may emerge *in the interim* – including the inefficiencies that we set out in the previous section.
285. Periodic resets also create additional potential problems. If a reallocation is only undertaken when changes in benefits exceed a pre-defined threshold, parties may have incentives to change their behaviour in inefficient ways so that this level is reached, i.e., if they will benefit from the attendant reallocation. Similar problems may arise if resets are undertaken every five years. As the date approached, parties might strategically alter their usage to appear ‘less of a beneficiary’.

¹⁵⁷ Intertemporal problems may also arise if Application B is applied. As the Options Paper points out, if parties benefitting from investments in the future are subjected to the AoB charge, competitive neutrality might suggest that the parties that are benefitting from the existing sunk assets should also be subject to the AoB charge. See: Options Paper, §6.62.

286. Finally, we noted above that one of the four broad problems the Options Paper identifies with the current TPM is that it has been extremely contentious and constantly under review since its implementation. In our opinion, the periodic identification of beneficiaries associated with the AoB charge will not reduce the controversy and disputation costs surrounding the TPM. Rather, it is altogether more likely that they would increase considerably. This is clearly at odds with one of the Options Paper's core objectives.¹⁵⁸

5.3 Summary

287. The principal potential advantage of the AoB charge is that it may reduce the 'wedge' that exists between the charges levied on particular customers and the private benefits that they obtain from certain investments. However, the charge may give rise to significant inefficiencies if it is implemented as designed. For example, levying AoB charges on generators based on MWh has the potential to distort wholesale market outcomes and lead to higher prices, since:

- when generators formulate wholesale bids, they will factor in the AoB charges they expect to pay;
- these are not 'true' short-run marginal costs – they are *fixed sunk costs* that have been *made* variable by the AoB charge; and
- this may lead to generators being dispatched out of 'true' merit order (i.e., based on their 'true' SRMCs), resulting in inefficiently higher prices;

288. These potential inefficiencies may be compounded under both the 'static' and 'dynamic' charging approaches. In particular, the periodic assessment of beneficiaries is likely to cause ongoing and escalated disputation and controversy, i.e., the very outcomes that the proposed pricing options are ostensibly trying to avoid. It may also cause parties to change their conduct in undesirable ways in order to appear 'less of a beneficiary'.

¹⁵⁸

Although, as we noted in section 2.4, given the large wealth transfers that can be associated with transmission pricing reforms, the TPM is always going to be a controversial subject. It is consequently questionable whether 'reducing controversy' is a very realistic objective. As we explained, the key goal should be to arrive at an efficient methodology, since these are inevitably the most durable.

6 LRMC, SPD and Residual Charges

289. In this section we review the LRMC and SPD charges that represent potential extensions to the proposed ‘base option’. We also examine the residual charge that the Options Paper proposes to levy on both EDBs and major industrial consumers.

6.1 LRMC charge

290. An LRMC charge is intended to provide a forward-looking signal to transmission grid users of the long-run consequences of their actions. If a party’s usage contributes to congestion on a line, this may bring forward the need for new capital investment – a consequence such a charge can foreshadow. As we explained in our response to the CBA Working Paper, this LRMC is not necessarily reflected in nodal prices in the wholesale market, i.e., there can sometimes be a “gap”.¹⁵⁹

291. As we have explained in our previous reports,¹⁶⁰ an LRMC price could, in *principle* represent a useful addition to the TPM. A key potential benefit is that, unlike the deeper connection, AoB and SPD charges, it would provide an efficient time profile of prices, under which the signal would strengthen as the need for new investment approached, and weaken afterwards. This would meet one of the key objectives in the problem definition.

292. One potential drawback of the marginal incremental cost (MIC) methodology proposed in the Options Paper is that it would be likely to be more volatile than the long-run incremental cost (LRIC) and average incremental cost (AIC) approaches. We explored the potential for such volatility in an earlier report.¹⁶¹ However, as the Options Paper acknowledges, there may be a trade-off between providing a ‘smoother’ signal (such as under an AIC approach) and providing the ‘right’ signal in the circumstances.

293. The Options Paper also highlights a number of challenges that would need to be overcome before a robust LRMC charge could be implemented. For example, various thresholds are proposed for determining which planned investments will be included and the relevant timeframes. We do not have any specific comments on these detailed design elements, other than to say that they would need to be examined carefully in the second Issues Paper.

¹⁵⁹ CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §57.

¹⁶⁰ See in particular: CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, section 3.3.

¹⁶¹ *Ibid.*

294. Our principal observations on the charge relate instead to its *size*. The price that has been preliminarily estimated is currently very low.¹⁶² This is unsurprising, given the point in the investment cycle. As we explained in section 2.1., because Transpower has just completed a large round of investments, there are now far fewer major investments to ‘signal’ to users, and they are not scheduled to take place for some time, so their LRMC is very low. This is a consequence of the time-dependent fluctuations one often sees in LRMC when investments are ‘lumpy’; namely:
- in the years immediately following new investment the LRMC of the next increment to capacity is low, because the value of any potential deferral of that future capacity requirement is relatively low due to the effect of discounting.¹⁶³ An LRMC-based price that reflected such circumstances at that time would therefore tend to encourage the use of that infrastructure – which is precisely what one observes with the estimated MIC charge; and
 - as spare capacity declines over time and the need to invest in new capacity approaches, the LRMC of the next increment to capacity increases, because the value created through any potential deferral higher is closer in time and so less (negatively) affected by discounting. An LRMC-based price at that time would desirably discourage the use of that infrastructure, thereby delaying the imminent need for new capacity.
295. As we explained in our response to the CBA Working Paper,¹⁶⁴ because LRMC oscillates through time, so too do the *benefits* that any such price signal can deliver. In this particular instance, because major new investment is not going to be needed for many years, the benefit of pushing back those future expansions is currently very small in NPV terms (as indicated by the low level of the LRMC charge). It is for this reason that we questioned in section 2.1 whether there was likely to be any material dynamic efficiency benefit from implement such a charge now.¹⁶⁵
296. In other words, although we agree that a LRMC price signals can promote dynamic efficiency *in principle*, we do not consider that there would necessarily be material benefits in *this particular instance*, given the point in the investment cycle. Moreover, as we explained in section 2.1, the existing RCPD charge already has the capacity to provide a signal to users to reduce peak usage when a region becomes susceptible to congestion. It is therefore not altogether clear what additional value an LRMC charge would add in any event.

¹⁶² This is most apparent in Figure 1 of the Options Paper.

¹⁶³ This is because the cost of bringing forward by, say, one year, an investment that would otherwise have taken place in 20 years is relatively modest in net present value (NPV) terms. In contrast, the MIC of a permanent increase in demand that brings forward to today the cost of a major investment that would otherwise have taken place in 2 years is likely to be substantial

¹⁶⁴ CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §63.

¹⁶⁵ This will need to be reflected in the quantitative CBA in the second issues paper.

6.2 SPD charge

297. The SPD charge involves identifying the beneficiaries of certain investments by applying the SPD model to selected assets and allocating the costs to beneficiaries in proportion to their share of private benefits. It does so by comparing actual historical wholesale market outcomes to hypothetical modelled scenarios in which certain elements of the grid are removed. Our previous reports – and the submissions lodged by the vast majority of parties – identified many problems with this charge. Steps have been taken to address some of these shortcomings, such as:

- the revised proposal calculates net rather than gross benefits;
- a monthly cap rather than a half-hourly cap has been introduced to ensure that more income can be recovered during peak usage times;
- retailers will not be required to pay the charge; and
- as we noted earlier, the EA is considering changes to the model to allow more recovery in the later years of an asset's life, when private benefits are generally greater, e.g., using non-depreciated replacement cost valuations.

298. In our opinion, these changes have improved the methodology (or, in the case of the time profile adjustment, will improve it if implemented). However, some of the most significant potential problems with the approach remain. For example, we explained in detail in our response to the Beneficiaries Pay Working Paper how the charge might cause generators to alter their bidding conduct in inefficient ways to reduce their exposure to it.¹⁶⁶

299. Under the SPD model, a generator's private benefit is equal to the difference between its bid and the market clearing price. It is consequently not hard to imagine that a generator might seek to reduce the extent to which it is perceived to benefit from an asset by increasing its bid above its SRMC – something that it would have no incentive to do under the current TPM.¹⁶⁷ As the Options Paper highlights¹⁶⁸ – in doing so, the generator risks:

- not being dispatched at all; or
- not being called upon to generate as much, i.e., generating a reduced quantity.

¹⁶⁶ CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.4.

¹⁶⁷ Although, as the EA and Transpower have recognised, the HAMI charge does sometimes result in certain generating units ramping down their output in order to avoid contributing to their HAMI.

¹⁶⁸ See Options Paper, footnote 119. This explanation reflects the more or less identical description in section 2.4 of our report in response to the Beneficiaries Pay Working Paper.

300. As we explained in our earlier report,¹⁶⁹ generators might therefore seek to optimise the trade-off between lowering transmission charges (by bidding above SRMC) and increasing the probability of not being dispatched, with the attendant negative effects on profitability.¹⁷⁰ We observed that if this type of behaviour became widespread it could seriously compromise the efficiency of the wholesale market.¹⁷¹ The Options Paper expresses the same view. It concludes that:¹⁷²

‘...manipulating offer prices in an attempt to avoid the SPD charge may have adverse consequences but it is not certain how large this problem would be in practice.’

301. In other words, the Options Paper highlights the potential for the SPD charge to give rise to this outcome, but notes that it is unclear how significant that problem would be. We agree that it is difficult to predict *ex ante* how serious this issue would be in practice, but it cannot be dismissed. In our opinion, it would be imprudent to underestimate the ability of sophisticated participants in a ‘repeated game’ setting to inefficiently change their bidding behaviour to improve their profitability.

302. A further problem with the SPD charge is that it would cause generators’ cash-flows will be less certain. As we explained in our first report,¹⁷³ this may result in additional risk premiums being incorporate in wholesale (and, in turn, retail) prices. The consequence is that prices in the wholesale market may be higher everywhere, irrespective of whether generators engage in the above conduct, i.e., adjust their bidding conduct to try and reduce their SPD charges.

303. Finally, problems may also arise from the intricacy of the charge. As we explained in our previous reports,¹⁷⁴ if the approach is implemented, the cost of disputes would be likely to increase, since parties would be likely to agitate for modelling inputs to be changed in ways that favour them. Moreover, as we explained in section 4.4, given the complexity of the SPD modelling this may limit the ability of some parties to engage constructively in the Commission’s new investment processes.

¹⁶⁹ CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §87.

¹⁷⁰ This depends, in part, on how accurately generators can forecast the market clearing price.

¹⁷¹ CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §87.

¹⁷² *Ibid.*

¹⁷³ CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 5.1.

¹⁷⁴ See for example: CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013, section 3; CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, section 2.

6.3 Residual charge

304. The Options Paper states that the residual charge should be designed so as to limit distortion in the use of the grid resulting from its imposition.¹⁷⁵ The proposal is to apply a flat, postage stamp capacity charge on load. However, this is allocated differently as between EDBs and major direct-connect customers:

- for EDBs, the intention is to levy the charge based on the sum of the nominal capacities of the active ICPs in their network areas;¹⁷⁶ and
- for direct-connect customers, the proposal is to levy the charge based on their respective AMDs.

305. The net effect of this inconsistent treatment is that the overwhelming majority – more than 97%¹⁷⁷ – of the residual charge is allocated to EDBs. As we explained in section 3.7, in our opinion, this differentiation is not well justified, because:

- although the capacity of some direct connect customers' connections substantially exceeds their AMD – this is also likely to be true of many EDBs, and so it does not provide a sound rationale for the distinction;
- although EDBs may have an incentive to inefficiently suppress load to avoid an AMD-based charge, this could be avoided by retaining an RCPD charge which is measured over a large number of periods, e.g., 100+; and
- EDBs may also seek to inefficiently reconfigure their assets so as to limit their exposure to the charge, e.g., by constructing micro-grids so as to reduce their numbers of ICPs.

306. For those reasons, we do not consider that a robust economic rationale has been provided for the large reallocation of sunk costs – and attendant price effects – that would result from its proposed application of different parameters to EDBs and major users. In the absence of a robust efficiency justification (which has not been supplied), there would seem to be no obvious reason for differentiating between these two categories of offtake customers in this way.

307. In contrast, there are potentially compelling reasons to maintain the existing RCPD charge. As we noted above, at the present time, when capacity is plentiful, it can be measured over a large number of periods so as to not unduly discourage parties from using the grid. However, when constraints start to emerge, Transpower could

¹⁷⁵ This is based on the assumption that a pricing signal is not necessary to promote efficient investment in capital expenditure less than \$20m not already covered by the connection or deeper connection charges. See: Options Paper, §6.93.

¹⁷⁶ Options Paper, §6.102.

¹⁷⁷ EDBs estimated total installed capacity is 47,044MW and major industrial's cumulative AMD is only 1,252MW, and so EDBs are allocated 97.4% of the 48,297MW total capacity ($47,044 \div [47,044 + 1,252]$).

reduce the number of peaks (e.g., back to 12) so as to signal those capacity shortages and the impending need for new investment.¹⁷⁸

6.4 Summary

308. The various changes that have been made¹⁷⁹ to the SPD methodology have improved the approach, but many more potential 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. This would compromise the efficiency of the wholesale dispatch process and needlessly increase prices.
309. The SPD charge would also make generators' cash-flows less certain, which may result in additional risk premiums being incorporate in prices, compounding the effect described above. The complexity of the methodology may also result in parties continually agitating for modelling inputs to be changed in ways that favour them. Furthermore, the intricacy of the approach may limit some parties' ability to engage constructively in new investment processes.
310. The proposed LRMC charge has the potential to promote dynamic efficiency *in principle*, by signalling to users the future costs of transmission investments. However, we do not consider that there would necessarily be material benefits in *this particular instance*, given the point in the investment cycle. There are currently few major investments on the horizon, which means there are 'not many costs to signal'. This reduces the achievable dynamic efficiency benefits.
311. Finally, no robust explanation has been supplied for the proposal to levy the residual charge in one way on EDBs and in another on major industrial customers. In particular, no compelling reason has been offered for departing from the RCPD charge (albeit perhaps with N=100 in all regions). This is a conspicuous omission, since the proposed approach would result in a far greater share of the residual charge being levied on EDBs.

¹⁷⁸ This could be done reasonably expeditiously through an Operational Review, much like the process that has recently concluded.

¹⁷⁹ We note that the EA has only stated that it is *considering* making changes to address the inefficient time profile of the charge. If those changes are not made this will, of course, remain a serious problem.

7 Application A versus B

312. Two potential applications of the proposed pricing reforms are set out in the Options Paper: ‘A’ and ‘B’. Application A would involve applying any new charges to both new and existing assets and investments.¹⁸⁰ Application B would involve applying new charges to recover the costs of new assets/investments only – with all other costs recovered through the existing charges. In this section we consider the respective merits of these two options.

7.1 Efficiency trade-offs

313. The Options Paper provides a reasonably comprehensive overview of the considerations that are important when determining the relative efficiency of the two applications.¹⁸¹ First, it rightly concedes that changing the TPM cannot affect the dynamic efficiency of investments that have already been made. Rather, the principal potential dynamic efficiency benefit from the options would arise from applying the charging methods to new investments.¹⁸² This would tend to suggest that Application B should be preferred from a dynamic efficiency perspective.
314. However, as we explained above – and as the Options Paper also highlights¹⁸³ – one must also remember that Application B might see the ‘wedge’ between the charges levied on particular customers and their private benefits growing over time to a point at which it starts to affect dynamic (and static) efficiency. If there is such potential (which is yet to be established, and requires further, careful consideration¹⁸⁴) this might then tip the balance back towards Application A on dynamic efficiency grounds.
315. However, the fact that Application A would serve to reduce any such ‘wedge’ between current charges and the perceived level of benefits also represents its biggest potential drawback. In order to reduce that wedge, the transmission charges levied on some parties will need to increase. Under the proposed options, those increases would, in some cases, be substantial. As we have explained in depth in all

¹⁸⁰ There are certain limiting criteria with respect to the AoB and SPD charges.

¹⁸¹ We note though that the Options Paper again mischaracterises Application A as being ‘more cost reflective’ than Application B as it relates to existing assets. As we explained in section 2.2, that is not correct – *both* would be cost-reflective in an economic sense.

¹⁸² Options Paper, §11.5.

¹⁸³ Options Paper, §11.6.

¹⁸⁴ As we explained above, this is an empirical question that would need to be explored in depth in the second Issues Paper. There can be no *presumption* that inefficiencies will arise, or that now is the best time to reform the TPM to address such matter.

of our previous reports, major changes in the way that sunk costs are recovered risk giving rise to significant *static inefficiencies*.

316. We set out in section 2.2.2 that the current TPM has been designed with statically efficient transmission pricing principles in mind.¹⁸⁵ There is consequently relatively little scope to *improve* the efficiency of the usage of the grid over the near- to medium term. However, reforms involving Application A could *compromise* near- to medium-term static efficiency. Specifically, it may cause the ‘losers’ (and perhaps even the ‘winners’) from the reforms to change their behaviour in inefficient ways in order to avoid paying the charges. As we explained in sections 4 and 5:
- parties may seek to alter their behaviour to limit the extent to which they are subject to the deep connection charge, for example:
 - EDBs might have a strong incentive to invest – or sponsor investment – in distributed generation to reduce their AMD; and
 - in a similar vein, generators may strategically withhold capacity in order to reduce their AMI;
 - charging generators AoB charges on the basis of MWh risks compromising the efficiency of the dispatch process, since they will face varying additional ‘marginal’ charges to reflect costs that are *not* marginal (i.e., sunk costs), which may disrupt the ‘true’ merit order; and
 - under any ‘dynamic’ variant of the AoB charge (which, in our view, are the only plausible options), there may be incentives for parties – particularly generators – to change their use of the grid in any attempt to change the set of parties identified as beneficiaries.
317. It follows that the biggest question insofar as the choice between Applications A and B is concerned is whether these potential short- to medium-term efficiency costs would be outweighed by the potential longer-term efficiency gains. There is also the related question of whether *now* is the best time to be reforming the TPM with a view to achieving those longer-term objectives or whether, given the point of time in the investment cycle, it would be better to wait – particularly if doing so would mitigate any adverse near term effects.
318. Finally, we note that if these conflicting near- and long-term effects are likely to ‘cancel each’ other out – or, at least, if one does not clearly outweigh the other – there may still be a case for favouring Application A if this will address perceived ‘inequity’ in the balance of charges. Put another way, if there are no obvious adverse

¹⁸⁵ We noted in particular that the methodology bears a strong resemblance to a “Ramsey-Boiteux” two-part tariff. Recall also that Transpower is in the process of addressing some of the static inefficiencies that have emerged in the RCPD and HVDC charges following the wave of recent investments through its Operational Review. Once that process is completed, the use of the transmission grid is likely to be very ‘statically efficient’.

efficiency implications from reallocating sunk costs, a reform might still be justified on the basis of ‘fairness’.

7.2 Other practical considerations

319. The previous section focussed primarily on the potential efficiency implications of Applications A and B. However, there are other factors that might reasonably influence the choice between the two (or any alternative). Most notably, there is the question of whether it is *practicable* for Transpower to maintain two methodologies side-by-side, as it would be required to do under Application B. Indeed, the number of potential charges that it then might need to be put in place is very large.
320. Depending upon the option implemented, the ‘new’ charges that Transpower would be required to administer might include: connection charges,¹⁸⁶ LCE charges, static reactive charges, deeper connection charges (based on complex load flow tracing), AoB charges (based on past investment approval decisions) and either an LRMC charge or an SPD charge. It would then need to continue applying the existing HVDC and interconnection charges to recover the residual revenue.
321. A number of these charges – including the deeper connection and SPD charges – also involve complex quantitative modelling. In our opinion, it is consequently unclear whether Transpower should reasonably be expected to manage such a large and complex array of charges. There is also the question of whether industry participants can realistically be expected to understand such a complex methodology – a matter that we addressed in section 3.5.
322. In our opinion, these considerations would tend to steer one towards Application A, or, as we explain in section 8, an alternative that is simpler still. It would also favour pricing options with ‘fewer moving parts’ (i.e., fewer charges). Greater simplicity would make it easier for Transpower to administer the methodology and, in turn, for industry participants to understand the approach and engage in consultations in a more informed and constructive way.

7.3 Transition paths

323. We explained above that the choice between Applications A and B should be determined primarily by competing efficiency effects. On the one hand, there is a concern that, unless Application A is selected, the ‘wedge’ between the transmission charges that parties pay and the benefits they derive will grow over time, potentially compromising long-term efficiency. On the other hand, because Application A entails much greater wealth transfers – and would involve much larger price

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These might be the same as the status quo, but the EA has not ruled out changes.

changes – it has greater potential to harm static efficiency over the near- to medium-term.¹⁸⁷

324. In recognition of this trade-off, the Options Paper proposes a series of ‘potential transition alternatives’. Each of these transition mechanisms is intended to ‘help manage the potential increases in transmission charges’ that would result under Application A, i.e., the application that would result in the biggest wealth transfers and price changes.¹⁸⁸ The key objective appears to be to strike the right balance between minimising short-to medium-term distortions to grid use (i.e., static inefficiencies), whilst still promoting any long-term gains in efficiency. Four alternatives are proposed:¹⁸⁹

- three of the alternatives – 2, 3 and 4 – involve capping in different ways the extent to which transmission charges are permitted to increase each year; and
- the remaining option – alternative 1 – would place a permanent cap on transmission charges to EDBs (but not to non-EDBs).

325. The fact that the Options Paper has proposed these transition mechanisms appears to suggest a level of discomfort with the ‘unadulterated’ forms of Application A and B. In particular, rightly or wrongly, the implication seems to be that:

- Application B would not provide sufficiently strong price signals to promote long-term efficiency; but
- because Application A would lead large price changes, this may unduly compromise efficiency over the near- to medium-term.

326. Put another way, there seems to be a concern that Application A may involve ‘too much’ re-balancing and that Application B may involve ‘too little’. The transition paths might therefore be characterised as ways of finding a ‘middle ground’. However, as we explain below, the trouble with these mechanisms is that, although they can smooth the near-term price effects, they cannot address the underlying efficiency problems. We address each type of mechanism in turn.

7.3.1 Capping the rate of change

327. A reasonable case can be made for capping the annual rate of change in prices in order to reduce any ‘price shocks’ to final customers. As the Options Paper notes, this is consistent with the approach taken by the Commission in setting electricity

¹⁸⁷ As we explained above, the larger the redistributions of sunk costs – and the bigger the attendant price changes – the greater the incentives that parties will have to alter their behaviour in inefficient ways to avoid paying those charges.

¹⁸⁸ Options Paper, §12.3.

¹⁸⁹ Options Paper, §12.8.

and gas distribution prices. In this respect, alternatives 2, 3 and 4 may each offer some advantages over an ‘unadulterated’ version of Application A. Those benefits are primarily grounded in notions of *equity*. In short, large price increases are often seen (rightly or wrongly) as ‘unfair’ – noting again that ‘fairness’ in an intrinsically subjective concept¹⁹⁰

328. On the other hand, smoothing the incidence of reallocations over several years¹⁹¹ does not necessarily avoid any near- to medium-term distortions to grid usage that would otherwise arise in the absence of that cap on the annual rate of change, i.e., it does not preclude any *inefficiency*. If a party is expected to change its behaviour in an inefficient way if prices increase by 10% under Application A, then spreading that increase over, say, five years is unlikely to avoid that conduct, since:

- the party may see that it will be paying 10% more in five years’ time and simply change its behaviour now to avoid that future increase, notwithstanding the more modest near-term implications; or
- it will simply change its behaviour in the future (e.g., after a few years) – the chief benefit of the transition mechanism in this instance would be that it delays that inefficient conduct, but it does not *avoid* it.

329. In other words, transition mechanisms that cap the annual increase in charges do not serve as a panacea to short- to medium-term efficiency problems. At best, they can only *delay* distortions to consumption decisions and, at worst, they will have no effect whatsoever. For that reason, in our opinion, if a pricing reform is expected to give rise to significant inefficiencies under Application A, transition mechanism alternatives 2, 3 and 4 will not fix that problem.

7.3.2 Temporarily capping prices for EDBs

330. Alternative 1, which would permanently cap EDB charging rates (in per-MWh terms) at about \$22/MWh¹⁹² *might* mitigate any near- to medium-term distortions to consumption decisions *from EDBs*. This is because prices may never reach the levels that might otherwise prompt those changes in behaviour, i.e., a party that would have faced a 10% increase in price under Application A may face a smaller increase due to this cap.¹⁹³ However, significant inefficiencies may remain.

¹⁹⁰ For example, other parties who would see their prices decrease under the various options would no doubt claim that it would be ‘fairer’ for them if their own prices declined *more quickly*.

¹⁹¹ We note that alternative 2 would involve most of the price increases occurring over the first two years, which would still result in large year-on-year increases.

¹⁹² This represents the upper quartile of all pre-capped EDB charging rates.

¹⁹³ That is, it would not face a 10% increase spread over a longer period.

331. The chief reason for this is that charges faced by generators and direct-connected load would remain *uncapped*. Of the parties paying for transmission, these are the most likely to change their behaviour in inefficient ways to avoid paying charges. The incentives of EDBs to avoid transmission charges can be expected to be at least partly diminished by the fact that they constitute a recoverable cost under their regulatory price paths. The same cannot be said for generators and transmission-connected load.
332. For that reason, alternative 1 is also unlikely to address any near- to medium-term distortions to grid usage precipitated by the large price changes resulting from Application A. We note also that the approach appears to run contrary to what the pricing reforms are ostensibly trying to achieve. Arguably, the principal long-term goal is (rightly or wrongly) to remove the ‘wedge’ between what parties are paying for the existing sunk assets and the perceived benefits they derive from them – partly for efficiency reasons, but also because it clearly views this as ‘fairer’.
333. That being the key motivation, it would be somewhat unusual to put in place a transition mechanism that could see that wedge remaining in place in perpetuity – albeit only for some EDBs. This would presumably limit the extent to which the pricing options could deliver any potential efficiency gains over the longer term (assuming that such potential exists). In other words, application 1 would not avoid any short- to medium-term efficiency costs, and might also limit the extent to which long-term efficiency gains can be achieved.
334. This inconsistency is implicitly acknowledged when the Options Paper notes that this transition mechanism would likely need to apply for only a *limited* period of time, such as three years, since otherwise some EDBs would never ‘fully transition’.¹⁹⁴ Of course, if the transition path is only in place for three years – and would then be replaced by one of the other alternatives (or an unadulterated version of Application A), then all of the problems that we described in the previous section would again apply.
335. It follows that neither capping the rate of change nor the prices applied to EDBs will prevent any inefficient changes in behaviour that are expected to occur in the absence of those transition mechanisms. All that this can achieve is to potentially delay the onset of any inefficiency, and to produce ‘fairer’ price changes, i.e., smooth price shocks (noting again that ‘fairness’ is an inherently subjective concept). If the objective is to avoid inefficient changes in behaviour *altogether*, a different approach will need to be adopted.
336. Specifically, if the EA believes that a more efficient – and fairer – allocation of charges might be obtained by changing the way in which sunk costs are recovered, but that Application A would result in “too much” rebalancing (i.e., cause parties to

¹⁹⁴ Options Paper, footnote 157.

inefficiently change their behaviour), then transition mechanisms will not solve this problem. Rather, it will be necessary to employ a methodology that does not result in such dramatic price changes.

337. In section 8, we set out some alternative methodologies that, in our view, may facilitate this outcome. Namely, they would generally result in higher charges for the perceived beneficiaries of recent investments (as set out in the Options Paper) – but those price increases would not be as substantial as those associated with Application A. In addition, consistent with the observations set out in sections 3.5 and 7.2, they would be significantly less complex than the proposed options.

7.4 Summary

338. From an efficiency perspective, the choice between Applications A and B primarily boils down to the potentially competing impacts upon dynamic and static efficiency from changing the way that the sunk costs of existing assets are recovered. From the perspective of dynamic efficiency:

- changing the TPM cannot affect the efficiency of investments that have already been made – it can only effect new investments that are made in the future, which might steer one towards Application B; but
- Application B might result in a growing disparity between the charges parties pay and the benefits they obtain which, as we set out above, might affect investment over the long-term and steer one towards Application A.

339. From the perspective of *static* efficiency, the biggest problem with Application A is its potential to disrupt grid usage decisions over the near- to medium term. As we explained in detail in sections 4 to 6, the deeper connection, AoB and SPD charges all entail these risks. This creates a potential dilemma:

- on the one hand, the Options Paper appears to suggest that Application B would not result in *enough* rebalancing, i.e., the ‘wedge’ between ‘prices and benefits’ would remain too great; but
- on the other hand, the implication seems to be that there may be *too much* rebalancing under Application A, i.e., the magnitude of the price changes may cause parties to change their behaviour in inefficient ways.

340. The proposed transition mechanisms appear to be an attempt to reach a ‘middle ground’ between these two extremes, i.e., to facilitate a reallocation of sunk costs, but to soften the impact of price changes. The trouble is that neither capping the rate of change nor the prices applied to EDBs will prevent static efficiency from being impaired. For example:

- if a party knows that it will be paying, say, 10% more in five years' time it may simply change its behaviour now to avoid that future increase, notwithstanding the fact that the transition to that new level may be 'smoothed'; or
- the party may simply change its behaviour in the future (e.g., after a few years) – the chief benefit of the transition mechanism in this instance would be that it delays that inefficient conduct; but it does not *avoid* it.

341. It follows that 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, a modification of the approaches set out in the Options Paper is required, as we discuss in the following section.

8 Implications and Alternatives

342. In this section we set out the implications of the analysis in sections two to seven for the pricing methodologies proposed in the Options Paper. We begin by summarising why the myriad shortcomings with those approaches are likely to render them unworkable, in practice. We then propose some alternative options that may go some way to achieving the key objective set out in the Options Paper, without necessarily giving rise to the same inefficiencies.

8.1 Implications for proposed pricing options

343. The Options Paper has raised potentially legitimate concerns about the long-term inefficiencies that may arise if the ‘wedge’ between the benefits that customer receive from transmission investments and the charges they pay grows over time. It also casts reasonable doubts about the potential inequity of the current allocation of sunk costs, which does involve some customers – often in the South Island – paying for investments – often in the North Island – for which they appear not to derive significant advantages.

344. As we have explained throughout this report – whether these are issues that warrant near-term regulatory intervention is an *empirical* question. For example, it could be that the ‘wedge’ described above will *not* grow materially over time or that the resulting inefficiencies would be modest – particularly if the TPM can adapt to address any such shortcomings that become evident (see section 2.1). Nonetheless, these potential problems *might* be sufficiently significant to warrant some modifications to the current methodology.

345. In the preceding sections we have explained how the approaches proposed in the Options Paper to address these potential problems are flawed in critical respects. We set out why the complexity of the approaches coupled with the design of the charges – including their propensity to allocate 100% of the costs of assets to small numbers of parties – risk harming dynamic efficiency. In particular, we explained that they may cause more unconstructive opposition to ‘good’ investments from parties lobbying for smaller assets to be built, or at a later date.

346. We also described why the proposed options would be simply unworkable in their current form. In particular, we set out why the many problems associated with prioritising the deeper connection charge over the AoB charge and the large implications for the proposed options of reversing this sequencing. We also highlighted the potentially substantial detrimental effects that the options are likely to have on short-term consumption decisions and static efficiency. We noted that these effects are likely to vary between Application A and B:

- Application A would involve more rebalancing of existing charges and would thus entail significantly greater price changes, which would increase the probability of parties changing their behaviour in inefficient ways; and
- Application B would involve less rebalancing and would entail fewer incentives for inefficient conduct, but it would not reduce the ‘wedge’ between ‘prices and benefits’ that is at the core of the concerns set out in the Options Paper.

347. We observed that the proposed transition mechanisms appear to be designed to navigate a ‘middle ground’ between these two extremes – presumably in recognition of this trade-off. However, as we explained in section 7.3, although those vehicles will soften the impact of price increases (which may seem ‘fairer’), they will not assuage the potential inefficiencies associated with Application A. At best, they will serve only to delay the onset of those inefficiencies and it is quite conceivable that they will make no difference at all.

348. The implication is that, even though potentially legitimate problems have been identified with the TPM, the methodologies proposed in the Options Paper are unlikely to represent the best way of addressing them. Those approaches should therefore not be countenanced as currently proposed. They are unlikely to be workable and may give rise to *more* inefficiency – not less. If the same basic suite of options is retained nonetheless then, as an absolute *minimum*,¹⁹⁵ they should be modified so as to:

- remove the inefficient time profile of the deeper connection, AoB and SPD charges, i.e., by applying annuity style depreciation or by using non-depreciated replacement cost values and applying an average depreciation rate; and
- reverse the ‘sequencing’ of the charges, i.e., by applying the AoB charge *before* the deeper connection charge for both new and existing assets – recognising that this would entail substantial additional work.¹⁹⁶

349. However, in our opinion, a better approach would be to consider more substantial departures from the ‘base option’ set out in the Options Paper.¹⁹⁷ There may be alternative pricing reform options available that will go some way to addressing what appear to be the chief potential concerns with the current TPM, but that may

¹⁹⁵ To be clear, the modifications described below would not address the many other problems with the charges we described in previous sections – many of which are simply *not* readily addressable.

¹⁹⁶ For example, it would be necessary to revisit every investment that meets the proposed criteria (including those covered by the proposed deeper connection charge) and allocate those costs *as if* they had arisen under the AoB framework.

¹⁹⁷ In truth, there is really only *one* option proposed in the paper – with two different ‘added extras’. To put it colloquially, this is not unlike a restaurant menu that features only one item – say, steak, eggs and chips – but with the option of adding either garlic or mushroom sauce. In our view, it is questionable whether these can reasonably be characterised as distinct options for the diner.

not entail quite the same drawbacks. Specifically, there may be other methodologies on offer that:

- result in *some* rebalancing of the sunk costs of past investments (including the \$2b of recent investments), but with more modest wealth transfers than those associated with Application A (and thus potentially fewer distortions);
- provide more efficient price signals to consumers – including over time, i.e., signals that provide a clear indication to customers of the cost their choices impose on the transmission network;
- do not give rise to the intertemporal problems that would be caused by the ‘sequencing’ of the deeper connection and AoB charges under the approaches proposed in the Options Paper;
- provide positive incentives for customers – including those that have not actively engaged to date – to monitor transmission expenditure without simply aggravating unproductive price-shock motivated opposition;¹⁹⁸ and
- are more easily understood by all interested parties and more straightforward for Transpower to implement and operate – all of which will result in fewer transaction costs across the sector.

350. In the following sections, we set out some other options that have the potential to meet these objectives. To be clear, we are neither endorsing these options, nor suggesting that they would necessarily deliver net benefits. Those are ultimately empirical matters. Rather, we simply propose that there may be merit in including these methodologies in the second Issues Paper.

8.2 Modified ‘base’ option

351. Although the ‘base option’ is the simplest methodology presented in the Options Paper it is still very complex. As we explained in section 3.5, in addition to understanding the intricacies associated with the load flow tracing methodology underpinning the deeper connection charge, parties would also need to grapple with potential interactions between the charges, i.e., assets may ‘transition’ between the deeper connection and AoB charges over time. In light of these problems, one solution might be to simplify this ‘base’ option.

¹⁹⁸ As we explain in section 2.3, we not convinced that transmission pricing reform can have a material effect on the Commission’s new investment approval process in practice. However, it is certainly possible that the *wrong* reforms can give rise to additional, unconstructive opposition to ‘good’ (NPV positive) investments (irrespective of whether this affects the Commission’s final decision).

8.2.1 A simpler ‘base’ option

352. Using the existing ‘base option’ as a starting point, a more straightforward approach would be to cut down the number of individual charges that comprise the methodology. One possibility would be to:¹⁹⁹
- retain a modified version of the AoB charge;
 - remove the deeper connection charge; and
 - remove the residual charge and retain instead the existing RCPD-based interconnection charge.
353. Because the AoB charge would be given precedence under this approach, it would consequently be necessary to revisit every investment that meets the proposed thresholds and allocate those costs *as if* they had arisen under the AoB framework. As we explained in section 3.2.2., this would be a substantial undertaking, since many of the investments that have been earmarked for deep connection charges would meet the criteria.²⁰⁰
354. The AoB charge itself would also need to be modified to address the inefficient time profile of prices that it would otherwise yield (note that this step should be taken in all options involving this charge). As we explained in section 3.3, this can be achieved relatively easily by applying either annuity style depreciation or by using non-depreciated replacement cost values and applying average depreciation (as per the existing connection charging framework).
355. The deeper connection charge would then be removed from this option (the LRMC and SPD ‘additions’ would also be absent²⁰¹). However, as we explained in section 3.2.3, it is not altogether clear whether there would be a material role for the deeper connection charge to play under this option even if it was retained since, as we noted above, a large number of deeper connection assets would be reclassified.
356. The remainder of Transpower’s revenue requirement could then be recovered through a residual charge that resembles the current RCPD-based interconnection

¹⁹⁹ An alternative approach would be to retain a modified version of the deeper connection charge, and to remove the AoB charge. However, in our opinion, there are a number of additional problems with the deeper connection charge that are likely to give rise to additional inefficiencies, e.g., the challenges associated with applying it to new investments. There are also issues surrounding its applicability to the HVDC link, which do not affect the AoB charge to the same extent.

²⁰⁰ Another key question would be whether to allocate those AoB charges to the beneficiaries identified in the original investment approval documents, or based on an assessment of the beneficiaries of those assets *today*.

²⁰¹ We note though that the LRMC charge might still be considered as an ‘extra’ on top of this option, bearing in mind the factors that we set out in section 6.1.

charge.²⁰² As we explained in section 6.3, the RCPD-based approach appears to represent a superior option to the residual charge that has been proposed in the Options Paper, which has not been well justified.

8.2.2 Potential advantages and disadvantages

357. This alternative option would seem to offer several potential advantages over both the status quo and the pricing methodologies proposed in the Options Paper, including the ‘base option’; namely:

- it would allocate a portion of the sunk costs of past investments to the parties who are arguably the principal beneficiaries, but with more modest wealth transfers than those associated with Application A under the proposed options – in part because of the more efficient time profile of charges;
- it would serve to reduce the probability of the ‘wedge’ between private benefits and transmission charges growing over time (to the extent that is a problem in practice), which might otherwise have potential implications for static and dynamic efficiency, as well as the perceived ‘fairness’ of the TPM;
- it would address the intertemporal problems that would otherwise be caused by the prioritisation of the deeper connection charge under all of the approaches proposed in the Option Paper, since only the AoB charge would feature in this simplified methodology;
- the retention of the RCPD charge would enable Transpower to adjust the value of “N” to signal to customers when a region is or is not becoming susceptible to congestion, and also provide them with an indication to the impact of their actions on future investment requirements; and
- it would be simpler than the other options, which would make it easier for parties to understand and make meaningful contributions to the investment approval process,²⁰³ whilst reducing the costs to Transpower of designing, implementing and operating the methodology.

358. However, this option would also have downsides. As we noted above, revisiting and reallocating the costs of past investments currently earmarked for deep connection charges would be a sizeable and controversial undertaking. More generally, because the approach retains the AoB charge, it would exhibit all of the potential problems

²⁰² Specifically, we do not consider that a compelling reason has been provided to shift to the proposed alternative approach and the RCPD charge offers the additional benefit of being capable of providing a further price signal if regions become susceptible to congestion in the future.

²⁰³ As we set out in section 2.3, greater stakeholder engagement is viewed (rightly or wrongly) as a key to discovering efficient investments in the future.

described in sections 5 (aside from the time profile of charges).²⁰⁴ If these proved to be substantial, this alternative may not improve upon the existing TPM.

8.3 Reallocate the HVDC charge

359. Of all the aspects of the current TPM, the HVDC charge has been by far the most contentious. It may therefore be worth considering revisiting and potentially reallocating *just this charge*. As we explain below, there is good reason to think that the rationales for the current allocation – i.e., 100% on South Island generators – no longer apply to the same extent.

8.3.1 Rationale for current allocation

360. Since the establishment of Transpower on 1 July 1994, there have been a number of changes to the way in which the costs associated with the link have been recovered from grid users. Initially, it was decided that the relevant costs would be recovered from North Island load and South Island generators on a ‘beneficiary pays’ basis:²⁰⁵

‘The first category is to be charged to North Island customers, since one of the benefits of the HVDC link is to reduce the cost of energy to the consumers in the North Island. Another benefit of the HVDC link is the removal of the constraint that, under normal circumstances, would increase the value of the energy produced by South Island generators.’

361. HVDC charges were allocated between North Island load and South Island generators on the basis of a 53:47 per cent split, respectively.²⁰⁶ This arrangement applied from 1993 to 1996, at which point Transpower published changes to its transmission pricing arrangements. Most significant of the changes was a reallocation of the costs associated with the HVDC link such that South Island generators became fully responsible for *all* HVDC costs.²⁰⁷

²⁰⁴ Recall that one of the biggest problems with the AoB charge was the use of a MWh parameter to allocate costs to generators. Changing the parameter to something else (e.g., a peak injection or capacity based allocation) is likely to simply give rise to other distortions. As we explain in section 3.6.1, that is the fundamental challenge associated with levying transmission charges on generators.

²⁰⁵ See: Transpower New Zealand Limited, *Transmission Pricing 1993*, p.17.

²⁰⁶ The charge comprising the 53 per cent share allocated to North Island load represented the costs of providing the then ‘old’ 600MW link, while the 47 per cent share allocated to South Island generation was based on the estimated costs of expanding the HVDC link at that time.

²⁰⁷ Transpower New Zealand Limited (1996), *Pricing for Transmission Services: Introduction to the Pricing Methodology to be Applied from 1 October 1996 - Second Edition, An information booklet from The Transmission Services Group*, p.11.

362. A chief rationale for recovering all HVDC costs from South Island generators was the view that they accrued the bulk of the benefits,²⁰⁸ since the link transported energy predominantly for the South Island to the North Island.²⁰⁹ Since that time, South Island generators have argued that they are not the only beneficiaries of the HVDC link. That is undeniably true. They are not, and never have been the sole beneficiaries, since:

- North Island load also benefits since the link provides greater capacity at times of peak demand and gives them access to a cheaper source of generation²¹⁰ – the Electricity Commission conceded that ‘user pays’ principles would support also levying HVDC charges upon North Island consumers;²¹¹
- in dry winters, the link allows North Island generators to take advantage of higher prices in the South Island brought about by a lack of water in the South Island hydro-storage lakes – this also delivers benefits to South Island consumers during these periods; and
- the link also provides broader system-wide security and reliability benefits by augmenting the capacity of the transmission network – not only in dry-years – but these wider public benefits are not easily attributable to individual beneficiaries, since they are enjoyed by all market participants.

363. In our opinion, one therefore cannot say that the ‘bulk’ of the benefits of the HVDC link accrue to South Island generators²¹² and that this is a sound basis for them to pay the full cost. Rather, the chief rationale for the charge should be to recover efficiently the long-run costs of the link without causing undesirable distortions. Historically it had been thought that charging South Island generators *did* achieve this objective, because:

- they would not be in a position to avoid paying this charge, and so levying the charge solely on these customers was thought to be a non-distortionary means of cost recovery;

²⁰⁸ *Ibid*, p.8.

²⁰⁹ For a more detailed account of the history of the HVDC charge, see: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, pp.24-26.

²¹⁰ As noted above, in recognition of this fact, between 1993 and 1996 North Island load was allocated 53 per cent of total HVDC charges, with South Island generators making up the balance. Indeed, the Electricity Commission (2007) has conceded that ‘user pays’ principles would support also levying HVDC charges upon North Island consumers

²¹¹ Electricity Commission, *Transmission pricing methodology: Final decision paper*, 7 June 2007, p.23.

²¹² We note for example that the EA has estimated that more than 50% of the ‘private benefits’ of the HVDC link accrue to load customers. See: Electricity Authority, *Transmission Pricing Methodology: issues and proposal Consultation Paper, Appendix C Assessment of materiality of problems with HVDC charges under the current TPM*, 10 October 2012, §13.

- the variable costs of South Island generators (predominantly hydro) were small, and so transmission charges would not distort wholesale market bidding by, say, significantly disrupting the merit order of dispatch; and
- charging other beneficiaries such as North Island load would amount to charging load for a sunk cost, which was thought might reduce consumption below the social optimal.

364. However, with the passage of time it has become increasingly apparent that these rationales no longer apply – or at least not the same extent. As the EA, Transpower and others²¹³ have recognised, the existing HAMI-based charging arrangements appear to result in the inefficient use of existing generation capacity and have the potential to distort long-run investment decisions, particularly in mid-merit and peaking plant, since:

- certain South Island plants sometimes strategically withhold supply during times of peak demand so as to avoid contributing to their HAMI and having to pay additional HVDC charges; and
- a generator that locates in the South Island must pay HVDC charges and may therefore have an inefficiently strong incentive to invest in the North Island instead (this is particularly true for new entrants²¹⁴).

365. As we explained in section 3.6.2, the extent to which the HVDC charge is distorting generator's locational decisions is an open question, given the many other factors (such as the location of fuel sources) that may influence such decisions. However, as the Options Paper points out, if HVDC charges increase further in the future, and the 'wedge' between the charges that generators pay and the private benefits that they derive from the link grows, the more likely it is that such distortions will occur.

366. In short, there may indeed be merit in reforming the HVDC charge. The EA is consulting already on Transpower's proposal to change the HVDC charging parameter from a HAMI charge to an average MWh charge.²¹⁵ The principal objective is to improve operational efficiency by addressing incentives for some

²¹³ For example, see: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, section 4.5.

²¹⁴ The incremental effect of the HVDC charge on a new plant installed by a generator with a large existing portfolio of South Island assets may be less than for an equivalent investment made by a smaller generator, or a new entrant. This is because the HVDC charge is an allocation. This means that there may be an off-setting effect for the large, existing South Island generator, since the HVDC charges allocated to the *balance* of its portfolio will decrease.

²¹⁵ See: Electricity Authority, *HVDC component of Transpower's proposed variation to the Transmission Pricing Methodology Consultation Paper*, 23 June 2015.

South Island generators to inefficiently withhold generation when it is needed.²¹⁶ However, it may also be worth considering broader reform.

8.3.2 Potential reallocation

367. In addition to potentially changing the HVDC charging parameter, it may also be worth exploring whether it may be beneficial to reallocate the charge itself, i.e., to share the costs with parties other than South Island generators. This reallocation of HVDC costs could be undertaken whilst leaving the rest of the current TPM intact, or it could be combined in some fashion with the simple ‘tilted postage stamp’ option we describe in the following section.
368. The basic premise of the option would be to cease recovering 100% of HVDC costs from South Island generators, so as to reduce the ‘wedge’ between the HVDC charges they pay and the benefits they derive from the link from growing over time. If this discrepancy does grow, it could lead not only to distortions to the wholesale market (irrespective of the charging parameter that is applied²¹⁷), but also sub-optimal investment decisions.
369. This approach bears *some* resemblance to the EA’s proposed AoB charge. The key difference is that it would have a *much narrower application*. The focus would be on addressing potential inefficiencies that have been identified with one specific charge. Some of the possible allocations that might be adopted include the following:²¹⁸
- using an up-to-date estimation of the array of ‘private benefits’, such as that undertaken by the EA in its first issues paper and summarised in Table 6 of its Options Paper – the allocations for Pole 2 and Pole 3; or
 - reapplying the 53:47 split that applied from 1993 to 1996, i.e., 53% to North Island load and 47% to South Island generators (noting that this allocation related to Pole 1 and Pole 2 – not Pole 2 and Pole 3); or

²¹⁶ Although, for the reasons we set out in section 4.5, there is also potential efficiency problems associated with a MWh charge.

²¹⁷ See explanation in section 3.6.1.

²¹⁸ Note that, under some of these options, the allocation could be varied as between Pole 2 and Pole 3, e.g., if the beneficiaries of the two assets are estimated to be materially different. The allocation of any *future* HVDC costs, i.e., new investments such as “Pole 4”, might consequently be influenced by the selected approach. For example, if a simple 50:50 split between South Island generation and load is proposed for existing assets, this might also be applied to any future expansions. Alternatively, those new costs could be allocated to the beneficiaries identified at that time, much like under the proposed AoB charge. In short, there are many potential approaches.

- a simple 50:50 split between South Island generators and North Island load – or even a 50:50 split between South Island generators and *all* load (since South Island consumers may also derive significant private benefits²¹⁹); or
- using an allocation of the share of flows across the link, i.e., based on the application of the EA’s load flow modelling approach (but perhaps without the attendant application of the HHIs).

370. Naturally, each of these approaches would have its advantages and disadvantages. One of the key trade-offs would be between trying to get the most accurate picture of private benefits on the one hand, and trying to keep the approach relatively simple on the other. In this respect, it is important to bear in mind that the search for absolute precision is likely to be forlorn one, since the pattern of beneficiaries will inevitably change over time (see section 5.2.2).

8.3.3 Potential advantages and disadvantages

371. In our opinion, this reform option could offer a number of potential advantages over both the status quo and the pricing methodologies that have been proposed in the Options Paper; namely:

- it would allocate a portion of the sunk costs of HVDC assets to a more representative group of beneficiaries, but with more modest wealth transfers than those associated with Application A under the proposed options, i.e., because it is reallocating *only* the HVDC charge;
- it would serve to reduce the probability of the ‘wedge’ between the HVDC charges South Island generators are paying and their private benefits from growing over time, which might otherwise have potential implications for static and dynamic efficiency, as well as the perceived ‘fairness’ of the TPM;
- generators would still be provided with a signal that it costs more for Transpower to serve them in the long-run if they locate in the South Island – although this price signal may be fairly ‘blunt’, depending upon the allocation selected, i.e., it may not accurately reflect LRMC, for instance;
- it would avoid the intertemporal problems that would otherwise be caused by the prioritisation of the deeper connection charge under all of the approaches proposed in the Option Paper, since the only change to the status quo would be a reallocation of the HVDC charge;

²¹⁹ The EA has estimated that South Island consumers potentially derive substantial private benefits from both Pole 2 and Pole 3. See: Electricity Authority, *Transmission Pricing Methodology: issues and proposal Consultation Paper, Appendix C Assessment of materiality of problems with HVDC charges under the current TPM*, 10 October 2012, §13.

- the retention of the RCPD charge would enable Transpower to adjust the value of “N” to signal to customers when a region is or is not becoming susceptible to congestion, and also providing them with an indication to the impact of their actions on future investment requirements; and
- it would also be much less complex than the other proposed options, which would make it easier for parties to understand and make meaningful contributions to the investment approval process and reduce the costs to Transpower of designing, implementing and operating the methodology.

372. However, this option would also have drawbacks. Because it bears some similarities to the AoB charging methodology, it would exhibit the same potential problems described in sections 5. However, these issues may not be as acute, given the more narrow application of the option, for example:

- the broader AoB charge would *add further* charges to generators, with the attendant problems set out in sections 4.6 and 5.2.1; whereas
- reallocating the HVDC charge would *reduce* the level revenue recovered from generators which could conceivably *mitigate* efficiency problems.

373. Having said that, the challenges surrounding the identification of beneficiaries and the allocation of charges described in section 5.2.2 may be comparable under this narrower approach. For those reasons, whether this alternative would represent a material improvement upon the status quo is something that will again ultimately need to be assessed in the second Issues Paper.

8.4 Differential interconnection rates

374. We observed in section 2 that one of the foremost concerns expressed in the Options Paper with respect to the TPM is that there are currently customers who are paying for investments that are being used to deliver services largely to *other* customers. Most of the options appear to have been designed explicitly to address that perceived problem. As we have explained throughout this report, this is typically done at a very ‘granular’ level, for example:

- the charges tend to be targeted at individual assets, e.g., identified through load flow tracing (in the case of deep connection charges) or by particular geographic locations (in the case of AoB charges); and
- in a similar vein, the charges for those assets are often sheeted home to quite specific parties, e.g., parties deemed to be ‘using’ an asset via load flow tracing or parties deemed to be the beneficiaries of an investment in a particular area.

375. This quest for specificity has numerous downsides. As we explained in section 3.1, none of the options will accurately necessarily identify all of the beneficiaries of particular assets or levy charges equal to their private benefits. They consequently

risk giving rise to the inefficiencies we have documented throughout this report. The approaches are also very complex, which may limit parties' capacity to understand the TPM and Transpower's ability to administer it cost effectively.

8.4.1 A more holistic approach

376. In light of the problems outlined above, it may be worth considering a more holistic approach. The Options Paper dwells extensively upon the perceived 'imbalance' between the interconnection charges levied on customers located in the North and South Islands. It implies that because many of Transpower's recent investments have benefited consumers in the north, by smearing those costs across *all* load:

- customers in the North Island are consequently not paying enough for the existing sunk interconnection assets; and
- customers located in the South Island are currently paying too much for those sunk assets.

377. The Options Paper suggests that this perceived imbalance may have potentially adverse effects on efficiency and, although it is not said explicitly, the clear inference is that the current allocation of interconnection costs is also 'unfair'. Assuming that this is indeed a problem that needs fixing (which remains to be seen), a potentially simpler way of reallocating the sunk costs of interconnection assets across load is by adopting a differential rating methodology.

378. At present, a 'flat' rate (\$/kW) is applied across all load to recover interconnection revenue, irrespective of location. Under a differential rates approach, different interconnection rates could be applied to off-take customers located in different geographic areas. There are various different ways in which these "differentials" might be applied, for example:

- a simple 'two island rate' could be applied, whereby off-take customers in the North Island paid a higher rate than customers located in the South Island; or
- charges could be applied to each of Transpower's existing interconnection regions – the LSI, USI, LNI and UNI – a 'regions' rates' option; or
- there could be more graduated differentials, e.g., with the interconnection rate increasing as one moved further north, or in bespoke locations.²²⁰

379. As with the HVDC charge (see previous section), there are a number of potential ways in which the different interconnection rates might be derived. One straightforward approach would be to derive the \$/kW charges by allocating

²²⁰ These options were explored in depth by the CEO forum in 2009, see: Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, section 5.1.

Transpower's interconnection revenue requirement to particular regions based on the value of its assets in those locations. For example (using round numbers):

- suppose that Transpower needed to recover \$600m per year in interconnection revenue, i.e., to cover the costs of those assets; and
- imagine that it wished to apply different interconnection rates in the North and South Islands, i.e., the simple 'two island rate' option described above; and
- suppose that its interconnection assets in the North and South Islands were valued at \$3b and \$1b, respectively; then
- in these circumstances, 75% of the annual cost (\$450m) would be allocated to North Island load and 25% (\$150m) to South Island load;²²¹ and
- the interconnection rates for each island would be calculated so as to recover those respective sums, and so the North Island \$/kW rate would be higher.

380. This option would assign costs to regions based on where assets are *physically located*, i.e., the greater the value of assets located in a region, the greater will be the applicable interconnection rate, all other things being equal. If there are only a small number of pricing regions (e.g., the North and South Islands), this allocation approach may provide a reasonably good indication of the chief beneficiaries of investments at an aggregate level. But that may not always be the case – especially as more and more regions are added.

381. Indeed, a potential drawback of this approach is that assets may sometimes be built in one region predominantly to transport electricity to another location, e.g., a link may be built in the lower North Island primarily to transport power to the Auckland region. Allocating the full cost of that asset to, say, a 'LNI' region would consequently not provide a good indication of the principal beneficiaries of that investment in that particular instance.

382. For that reason, if more than, say, two pricing regions are to be used an alternative – albeit more complex – approach might be to assign interconnection assets to those locations based on the application of the AoB charge methodology, or something analogous to it. For example, suppose that Transpower retained its four existing regions: LSI, USI, LNI and UNI. When contemplating a new investment, it might seek to identify the extent to which each of these regions is likely to benefit.

383. If a particular region was estimated to derive, say, 50% of the benefits of an investment, it might then be allocated half of the annual revenue requirement. Unlike the previous allocation approach, it would not matter where the investment was *physically* located – the attribution would be predicated on the perceive level of

²²¹ These percentages are calculated by dividing each islands asset value by the total asset value, i.e., \$3b ÷ \$4b = 0.75.

benefits (which might be estimated based on forecast usage as indicated by load flow tracing).

384. The same general approach could be used for existing interconnection assets, although there would be a separate question of whether to allocate those costs based on the perceived *original* beneficiaries (i.e., as set out in the original investment proposal documents) or on an updated assessment. A key point to note in both cases is that the costs of assets would not be allocated to individual customers, but to *the region as a whole*.
385. For example, suppose for the sake of simplicity that the grid comprises just two assets. Table 1 illustrates a hypothetical allocation of those two assets to off-take customers in the four existing pricing regions: UNI, LSI, USI and LSI. In the hypothetical scenario depicted in the table, a descending proportion of cost is allocated to the UNI, LNI, USI and LSI, respectively. The \$/kW interconnection rates in these locations would therefore be expected to reflect that pattern, i.e., be higher in the north and lower in the south.

Table 1 Allocation of interconnection costs

Revenue Requirement (\$m/year)	UNI	LNI	USI	LSI	Residual
Asset A - \$100m	50% \$50m	25% \$25m	15% \$15m	0% \$0	10% \$10m
Asset B - \$50m	30% \$15m	30% \$15m	20% \$10m	10% \$5m	10% \$5m
Total	\$65m	\$40m	\$25m	\$5m	\$15m

386. Note that Table 1 contains a column entitled ‘residual’. This category may be necessary if there are broader market benefits that cannot be sheeted home to particular regions, e.g., benefits arising from greater overall system resilience. These costs could be allocated to regions either equally or based on their respective shares of the *specifically assigned* interconnection costs. The \$15m residual from Table 1 would be allocated as follows under the these two approaches:

- under the first approach, the UNI, LNI, USI and LSI would each be allocated 25% of \$15m, i.e., \$3.75m per annum; and
- under the second approach:
 - the UNI would be allocated \$7.22m, i.e., $(\$65m \div \$135m) \times \$15m$;
 - the LNI would be allocated \$4.44m i.e., $(\$40m \div \$135m) \times \$15m$;
 - the USI would be allocated \$2.78m i.e., $(\$25m \div \$135m) \times \$15m$; and

- the LSI would be allocated \$0.56m i.e., $(\$5m \div \$135m) \times \$15m$.

387. The asset values used to allocate interconnection costs to regions could be the depreciated book values of the relevant assets, or the non-depreciated replacement costs. In our opinion, the latter would be superior. As we explained in section 3.3, because Transpower is required to apply straight line depreciation under its price path, using non-depreciated replacement cost values is likely to result in a more efficient profile of charges that is more stable over time.
388. If interconnection costs are allocated based on non-depreciated replacement costs, it is likely to make sense to update those attributions to reflect changes in those asset values. This could be done every five years, so as to coincide with the term of Transpower's regulatory price path, or every year – since it would be required to update its RAB annually for regulatory purposes. Given that interconnection charges are levied annually in lieu, the latter may be preferable.

8.4.2 Combination with other options

389. The differential interconnection rates methodologies described above could be maintained in conjunction with the existing RCPD-charge arrangements – or something close to them. Having calculated the interconnection charge *for each region* (e.g., the North and South Islands or the four existing regions) using the approach set out above,²²² the interconnection charge *for each customer* could be calculated by multiplying the relevant rate by each customer's average off-take at times of RCPD. Moreover, as we noted earlier:
- during times in which the region in question has surplus transmission capacity, this could be done over a large number of periods, e.g., 100 or more; and
 - when the need to undertake new investment approaches and constraints begin to emerge, the number of periods could be reduced, e.g., to 12.
390. Furthermore, as we foreshadowed above, this change could be implemented alongside the 'reallocated HVDC' option described in the previous section. In *principle*, one way of doing so would be to collapse the current distinction between the two types of assets and to recover HVDC costs through the interconnection charge. However, as we explained in section 4.2.3, in *practice*, there are good reasons for retaining distinct charges.²²³

²²² Recall that this may involve costs that were specifically assigned to regions, based on perceived benefits, as well as an allocation of 'residual' interconnection costs.

²²³ Specifically, from a practical perspective, the HVDC and interconnection assets are differentiated and treated separately in the regulatory arrangements administered by the Commission, i.e., there are distinct revenue streams and performance measures. In this sense, one could say that these assets are

8.4.3 Potential advantages and disadvantages

391. In our opinion, a simplified differential rates option might entail a number of advantages relative to the existing TPM and the other pricing approaches that have been proposed in the Options Paper; namely:

- it would enable the sunk costs of interconnection assets to be allocated amongst a more representative group of beneficiaries and, if that allocation is based on non-depreciated replacement cost values, the wealth transfers may be more modest than those associated with Application A under the proposed options;
- it may serve to reduce the probability of the ‘wedge’ between the interconnection charges that customers are paying and their private benefits from growing over time, which might otherwise have potential implications for static and dynamic efficiency, as well as the perceived ‘fairness’ of the TPM;
- it would not entail the intertemporal problems that would otherwise be caused by the prioritisation of the deeper connection charge under all of the approaches proposed in the Option Paper, since those charges would not feature in this alternative approach;
- because the RCPD charge could be retained, this would enable Transpower to adjust the value of “N” to signal to customers when a region is or is not becoming susceptible to congestion, and also providing them with an indication to the impact of their actions on future investment requirements; and
- it would once more be less complicated than the proposed options, which would enable parties to more readily make informed contributions to the investment approval process and it would also reduce the costs to Transpower of designing, implementing and operating the framework.

392. Of course, the options would also have disadvantages. Arriving at an appropriate allocation mechanism would be controversial and, as with the HVDC charge, there would be a trade-off between precision and simplicity. In our opinion, given that any allocation will – at best – only approximate the nexus of benefits, it may be better on balance to employ a relatively simple approach, e.g., a ‘two island’ or ‘regions’ rates.

393. Note also that if this option is combined with the previous ‘reallocated HVDC’ option, the ‘aggregate’ approach will also entail the potential advantages and disadvantages that we set out in section 8.3.3. As with the other options in this section, whether ‘stand-alone’ differential rates or an approach combined with the aforementioned HVDC reform represents a material improvement upon the status

distinguishable because they are *already* distinguished. For that reason, the best approach may be to maintain the differentiation between them.



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quo is again something that will need to be explored in depth in the second Issues Paper.

Appendix A Previous Reports

394. Throughout this report we have drawn extensively upon materials contained in earlier papers by CEG economists; namely:
- CEG, *Transmission Pricing Methodology – Economic Critique*, February 2013;
 - CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013;
 - CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013;
 - CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper*, 12 November 2013;
 - CEG, *Avoided Cost of Transmission Payments, A Report for Vector*, January 2014;
 - CEG, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014; and
 - Green et al, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009.
395. Where a matter has been explored in one or more of these documents, we have not sought to repeat all of that material in this report – even when it remains equally germane. Rather, in the interests of parsimony, we have provided a summary of the key points and supplied appropriate references to this earlier work.