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# Transmission Pricing Methodology – Economic Critique

February 2013

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# Executive Summary

1. The Electricity Authority (EA) has proposed material changes to the Transmission Pricing Methodology (TPM). Most significantly, it plans to merge the high voltage direct current (HVDC) link and interconnection charges and to recover a proportion of the required revenue from parties deemed to be ‘private beneficiaries’ of certain investments. Importantly, it proposes to use this ‘beneficiaries pays’ approach to set prices for new assets and for investments made since May 2004 exceeding \$2 million. This already encompasses a significant proportion of the grid and, in time, will capture all of it.

## General Observations

2. The EA’s perceived problem with the current pricing arrangements for HVDC and interconnection assets is that there is no direct link between those who benefit from a new investment and those who pay for it. Consequently, potential beneficiaries may have an artificially strong incentive to lobby for a new investment if they know that it is other parties (non-beneficiaries) that will ultimately bear the cost.
3. The proposed solution to this problem is to attempt to replicate the incentives that exist in well-functioning markets with clearly defined property rights. In workably competitive markets, beneficiaries are forced to pay for investments. This compulsion comes either through commitments that are made by foundation customers, or through competitive market prices subsequently being set to reflect the value that users place on the services provided by the relevant investment.
4. In such a market system, an investment will only be undertaken if the proponents have sufficient contracted demand for the service and/or are confident that future users’ willingness to pay will be sufficient to justify the cost. In other words, an investment will only take place if the present value of benefits to users (and hence their willingness to pay) is expected to exceed the cost of the investment. One way to attempt to achieve this outcome would be to institute a market-based process for initiating grid investments.
5. However, there are a number of reasons why attempting to deliver transmission investment through a market mechanism may not give rise to efficient outcomes (e.g., scale economies and difficulties in defining property rights - see Appendix A for more detail). Consequently, there is relatively little reliance placed on market based investment in electricity transmission sectors internationally, and nowhere is there sole reliance on this mechanism (at least, not as far as we are aware). The proposal is an attempt to deliver some of the benefits of a market based arrangement for investment without actually having such a system.

6. Specifically, it is proposed that all beneficiaries pay for an investment in proportion to the estimated *ongoing* benefits<sup>1</sup> that they derive from the existence of the asset over its life.<sup>2</sup> Under the proposal, beneficiaries will only have an incentive to lobby for an investment if the incremental benefits they anticipate receiving from it exceed their expected incremental allocation of total grid costs. Beneficiaries will have an incentive to lobby for the right investments if the methodology increases their total transmission charges by an amount that is proportional to their share of the benefits, multiplied by the total investment cost. Mathematically, this can be expressed as follows:

$$\text{PV of expected change in transmission charges for party } i \text{ consequent on investment} = \text{PV} \frac{\text{E}(\text{benefits of the investment to party } i)}{\text{E}(\text{total benefits of the investment})} \times \text{E}(\text{investment cost})$$

7. However, the proposed methodology may not create this efficient expectation of future cost allocations. This is not because of the informational difficulties associated with estimating potential benefits – although, these are great. The problem is more fundamental in nature. The difficulty is that the methodology does not simply allocate the cost of a new investment in a manner that reflects the benefits of that bespoke new asset. It also changes the allocation of the sunk costs of *past* investments. Specifically, a new investment can be expected to alter a party’s allocation of total transmission costs due to:
- it acquiring a share of the costs of the *new* investment, based on the extent to which it is deemed to be a beneficiary of that asset; plus
  - any change in the allocation of the costs of *all other investments* that is brought about by the new investment, e.g., a new investment in one part of the grid may change the extent to which parties are deemed to be beneficiaries of *other parts of the grid*.
8. There can be no dynamic efficiency benefits associated with applying a ‘beneficiaries pay’ approach to reallocating the sunk costs of *past* investments. Sunk investment decisions have been made and there is now no way to reduce the cost or change the nature of those outlays. However, sub-optimal outcomes can be created through such reallocations, since they can result in large wealth transfers that may cause

<sup>1</sup> This assessment is not made on a ‘one-off’ basis upon commissioning (at ‘ $t_1$ ’). Rather, as the profile of beneficiaries changes over time (at  $t_2$ ,  $t_3$ ,  $t_4$  and so on), so too does the nexus of private benefits and the quantum of transmission charges.

<sup>2</sup> Rather than having investors base their investment decision on a combination of firm contracts with users today and/or an assessment of future users’ willingness to pay.

market participants to act in ways that compromise both static and dynamic efficiency.

9. We are not aware of any transmission pricing arrangements that involve the perpetual reallocation of sunk costs. None of the international examples cited encompass such a practice. In fact, the US Court of Appeal decision that is discussed appears to caution against the practice.<sup>3</sup> As we noted above, significant inefficiencies may result from such reallocations, including increased disputation (together with the associated costs), reduced wholesale market efficiency and a systemic increase in risk throughout the supply chain (see below).
10. These potential adverse consequences do not appear to have been wholly accounted for in the quantitative cost-benefit analysis. The \$173.2 million in net benefits said to be associated with the proposal is predicated on a belief that the proposal will promote dynamic efficiency. In our view, the opposite is quite likely to be the case. The failure to factor in the negative impact on incentives from continual reallocation of sunk costs renders the basic premise of the proposal questionable.

### Greater Potential for Disputes

11. Under the proposals, once a new asset is built, this may change the way in which market participants pay for all of the other interconnection assets that have been built since May 2004 (that exceed \$2m). Moreover, day-to-day fluctuations in the wholesale market, changes in load profiles, and connections and disconnections will all affect the profile of private beneficiaries and, in turn, the transmission charges they are required to pay based on the Scheduling Pricing and Dispatch (SPD) model. These factors will increase the likelihood of disputes, because:
  - Market participants can be expected to view every new investment decision not simply on the basis of the direct costs and benefits of the asset in question, but on the basis of how that asset will affect their estimated benefits of every other part of the grid, and so the totality of their interconnection charges.
  - This means that the existing market participants may lobby for or against the construction of a new asset for reasons that have nothing to do with the direct costs and benefits of the bespoke investment but, rather, because they will become ‘larger’ (or ‘smaller’) beneficiaries of the rest of the grid.
  - In addition, because the interconnection charges that parties will pay will vary over time based on wholesale market outcomes, it is natural to expect that parties will perpetually agitate for changes to the SPD methodology that will serve to reduce their own transmission charges.

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<sup>3</sup> *Illinois Commerce Commission v FERC*, 576 F.3d 470, 476, pp.2-3.

12. The methodology is therefore unlikely to reduce the resources spent on lobbying and reviewing the methodology in the manner intended. Rather, it is more plausible that the scope for disputes will expand. In particular, introduction of the proposal may lead parties to advocate against efficient new investments (or for inefficient new investments) because they care primarily about the allocation of the sunk costs of *past* investments. This will harm dynamic efficiency.
13. One potential way of mitigating this last problem is to make a ‘one-off’ assessment of the beneficiaries of a new investment and require them to fund the investment in proportion to their estimated private benefit (either up-front or through ongoing annual fees). In other words, the perceived beneficiaries must commit to ‘writing a cheque’ (or a series of cheques) before the investment proceeds.<sup>4</sup>
14. Under this approach, once an investment is made, the parties that will pay for it have already been determined and are ‘locked in’, even if the market changes significantly in the future. Put another way, just as is the case in a market system, once costs have been sunk, so too is the responsibility for those outlays. It is only in these circumstances that parties will assess a new investment purely on the basis of their expected benefits and costs, in a manner consistent with workably competitive market processes (and the earlier formula).<sup>5</sup>
15. Of course, this would crystallise at the time of the investment what the proposal attempts to put off into the more distant future. Specifically, the allocation of benefits (via the running of a market model not just retrospectively each month, but out into the future over the life of the investment). Naturally, parties would still have a strong incentive to lobby on how that allocation is undertaken. But, if the modelling was accurate, they could be expected to only lobby for efficient projects (unlike the case where the modelling also reallocates sunk costs).
16. Of course, even here, dynamic efficiency would only be promoted if the estimation was accurate, i.e., if it reflected the true nexus of benefits. If it was not, then some parties may still have an incentive to lobby against/for investments that they perceived to be efficient/inefficient. Given the difficulties invariably associated with identifying beneficiaries, such an outcome is certainly conceivable.
17. There is also substantial scope for disputes to arise in relation to the way in which the SPD model is designed and implemented. For example, there are several inputs to the SPD model that have a significant effect on the incidence of charges, but which require a material degree of subjective judgement. These include (but are not

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<sup>4</sup> The beneficiaries identified today could also be given some rights over the extraction of value from future beneficiaries not currently in existence. Alternatively, the actual costs allocated to the beneficiaries identified today could be reduced by an estimate of the present value of benefits to parties not yet in existence.

<sup>5</sup> As opposed to assessing a new investment based on the expected benefits and costs of that bespoke new asset *plus* the change in the allocation of all other costs.

limited to) the value that are assigned to unserved demand – the ‘value of lost load’ (VoLL)<sup>6</sup> – and the time period over which benefits are estimated.<sup>7</sup>

18. The determination of these inputs may consequently attract particular scrutiny and controversy. The problem this creates is that there are no ‘unambiguously correct’ values for these parameters – there is significant scope for legitimate disagreement. Parties can be expected to continually agitate for these aspects of the methodology to be changed, knowing that even a small change in their favour may significantly reduce their charges. Locking-in these inputs for a period – say, for five years – does not necessarily assuage this problem, because:
  - there would inevitably be significant dispute over the initial values assigned to these parameters, and the values assigned at each subsequent review – given the potential value at stake, those disputes could conceivably culminate in costly litigation (judicial reviews);
  - because the SPD model would have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative model), there would be a wider ‘potential set’ of parameters over which there would be controversy when the TPM was set/revisited; and
  - the fact that the current TPM has been ‘set’ for prolonged intervals has not insulated it from ongoing controversy, and so there is no reason to think that ‘locking-in’ VoLL, the capping period and so on would prevent parties from constantly lobbying to have those parameters changed.
19. Moreover, as is often the case with sophisticated quantitative models, it is unlikely to be possible to fix every parameter in advance. Rather, we understand that Transpower will often need to make various ongoing judgements when defining counterfactuals in order to ‘solve’ the SPD model. The nature and effect of these judgements may vary depending upon the level of demand and other grid constraints (such as the location and availability of reserves). This constant (and unavoidable) recalibration creates an even more fundamental problem.
20. Specifically, if Transpower must make a ‘judgement call’ in order to solve the model during a trading period this may create clear ‘winners and losers’ (as is frequently the case with transmission pricing). Whenever a party finds itself on the ‘wrong end’ of judgment call, it can be expected to challenge that decision. Moreover, because the methodology will eventually encapsulate the entire grid, the frequency of those disputes – and the sums in question – will only increase over time. This is a recipe for ongoing controversy.

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<sup>6</sup> See: Transpower, Electricity Authority TPM Proposal (2012) – Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.13.

<sup>7</sup> See: Transpower, Electricity Authority TPM Proposal (2012) – Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.12.

## Potential for Inefficient Grid Use

21. The New Zealand wholesale market design means that, most of the time, generation plant should be ‘dispatched’ according to its economic merit order, as given by the ascending short run marginal cost (SRMC) of running each type of plant. The incentives created for efficient, least-cost dispatch are a defining feature of a market that is widely acknowledged as being at the forefront of international best practice. The regional coincident peak demand (RCPD) based interconnection charge is also generally viewed as being a positive feature of the New Zealand arrangements.
22. The proposal risks compromising both of these aspects of the market – with the offsetting benefit intended to be the promotion of dynamic efficiency. If transmission charges were to be levied upon generators in the manner envisaged, this will increase the opportunity cost of generating, and may result in higher wholesale prices. To be clear, wholesale prices will be higher not just in absolute terms,<sup>8</sup> but higher still than the level justified by that increased allocation.
23. This is because the ‘private benefit’ based charge and the RCPI charge (depending upon its design) will be additional variable costs that may affect generator’s bidding conduct in the following inefficient ways:
  - The ‘beneficiaries pay’ charge may cause generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments. When load can be served more cheaply by those generators, it is efficient for the pricing methodology to encourage the use of that infrastructure, not discourage it.<sup>9</sup>
  - Put another way, the proposal risks giving rise to a dispatch profile that no longer represents the ‘true SRMC’ based merit order. The consequence is that prices in the wholesale market will be higher in some parts of the country than if generators had not modified their conduct in this manner.
  - Generators’ cash-flows will also be less certain, which may result in additional risk premiums being incorporated in wholesale (and, in turn, retail) prices. The consequence is that prices in the wholesale market may be higher everywhere, regardless of whether generators engage in the above conduct.
  - The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge.
  - It may be possible to design the RCPI charge so as to mitigate those incentives and to preserve the existing properties of the RCPD charge, reducing the

<sup>8</sup> Higher wholesale prices are an inevitable consequence of a greater allocation of grid costs to generators.

<sup>9</sup> For example, in its paper, the EA acknowledges the possibility that generators might change their bidding conduct if its proposal is implemented. For example, it raises the possibility that South Island generators might bid so as to avoid being allocated the costs of Pole 3 of the HVDC link.

attendant distortions. However, even then, the charge seems not to offer any clear benefits, which is the relevant threshold for change.

- Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the ‘beneficiaries pay’ and RCPI charges. They may therefore under- or, more problematically, *over*-estimate those costs when formulating bids.

24. In our opinion, one should not risk compromising the efficiency of the wholesale dispatch process in order simply to identify the private beneficiaries of a past (sunk) investment. The perceived ‘benefit’ – identifying and charging only those parties that are ‘private beneficiaries’ – is only a ‘welfare neutral’ wealth transfer. In contrast, the higher wholesale prices that would result from generators adjusting their bids to avoid the incidence of sunk costs and to incorporate additional risk premiums are unambiguously harmful for consumers.

### Risk Amplification

25. The proposal has the potential to amplify risk throughout the entire supply chain, with myriad attendant consequences. Generators will face additional risks since the methodology will ‘marginalise’ costs that previously were either fixed (the HVDC charge), or recovered from off-take customers (interconnection charges). This will reduce the certainty surrounding their cash-flows and may result in higher, more volatile wholesale prices, for the reasons described above.
26. This has direct implications for electricity retailers who will be forced to pay those wholesale prices, as well as the separate SPD charges levied directly by Transpower. Both of these charges have the potential to be quite volatile, which will make it more difficult for retailers to forecast their input costs and to set retail tariffs – which are typically fixed for the course of a year. Retailers may respond to this uncertainty by incorporating additional risk premiums in their prices.
27. The heightened risk may also disproportionately affect smaller retailers. Larger retailers will often also own generation assets, and those ‘natural hedges’ may insulate them – if only to a degree – from wholesale energy price volatility.<sup>10</sup> They are also likely to have a greater stock of institutional capital (‘know-how’), which

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<sup>10</sup> These providers are sometimes called ‘gentailers’. By owning both generation and retailing interests, a business may insulate itself to a degree from the risk of high/low spot market prices by being on ‘both sides of the bet’, i.e., although its retail arm may face a high wholesale price, its generation arm may be commensurately receiving that same high price (although that is not necessarily the case if there is nodal price separation and a generating unit is distant from the retail load).

they can draw upon in order to better predict peak periods, and factor that information into their prices.<sup>11</sup>

28. Smaller businesses cannot address the heightened volatility through these means – and there is no way to hedge those risks through traditional financial instruments. These businesses may find it harder to enter the market and/or to expand if the proposal is implemented. This is potentially problematic because, although small retailers currently comprise only a modest share of the market,<sup>12</sup> they appear to have a significant disruptive influence on prices and service offerings.

## Summary

29. The EA proposes substantial changes to the TPM in its paper. The most significant is its plan to merge the interconnection and HVDC charges and to recover a proportion of the required revenue from parties deemed to be ‘private beneficiaries’ of certain investments. In our opinion, a robust foundation for that proposal has not been established. The following general observations can be made in relation to the proposed methodology:
- The methodology will be applied primarily to reallocate the sunk costs of past investments, including the approximately \$2 billion of new investments that have been recently approved (much of which is now completed). This encompasses a significant proportion of the grid.
  - Those investment decisions have been made and there is now no way to reduce the cost or change the nature of those outlays. However, changing the way in which the sunk costs are allocated will result in large wealth transfers and may cause market participants to act inefficiently (see specific points below).
  - The potential adverse consequences associated with reallocating sunk costs are not accounted for in the quantitative cost-benefit analysis.
  - The cited international precedent does not support the re-pricing of past investments – in fact, the US Court of Appeal judgment cautions against doing so. More generally, we are not aware of any transmission pricing arrangements that resemble what has been proposed.

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<sup>11</sup> Larger businesses may even be able to undertake load control during predicted periods of peak demand (e.g., switching off interruptible load) so as to reduce the quantum of transmission charges that they are assigned during those times.

<sup>12</sup> Currently, the largest electricity retailers and their subsidiaries (Contact/Empower, Genesis/Energy Online, Mercury/Bosco Connect, Meridian/Powershop and Trustpower) account for around 95% of the New Zealand market. (These shares are based on the percentage of energised installation control points (ICPs) held by each retailer as at November 2012. See: <http://www.ea.govt.nz/dmsdocument/14146>). The remainder of the market is made up of a number of small, independent retailers such as Tiny Mighty, Just Energy and King Country Energy (See: <http://www.switchme.co.nz/residential/power-companies.php>).

30. When one examines the particulars of the proposed changes to the interconnection and HVDC charge, the potential for inefficiency is even more apparent. Most notably:
- The proposal will increase the scope for disputes and in a manner that may lead some parties to advocate against efficient investments (or for inefficient investments) because they care primarily about the allocation of sunk costs. This will harm dynamic efficiency.
  - Parties can also be expected to perpetually agitate for changes to be made to the SPD methodology and to challenge any instances in which Transpower must make an unfavourable ‘judgement call’ in order to ‘solve’ the SPD model. This is a recipe for ongoing controversy.
  - The ‘beneficiaries pay’ charge risks causing generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments, resulting in a dispatch profile that no longer represents the ‘true SRMC’ based merit order. The RCPI charge may create further distortions if it is not designed carefully. The result in both cases will be higher wholesale prices.
  - Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the ‘beneficiaries pay’ and RCPI charges. They may therefore under- or, more problematically, *over*-estimate those costs when formulating bids.
  - The proposal seems likely to amplify risk throughout the supply chain in a manner that is impossible to hedge against. The reduced certainty surrounding cash-flows is likely to manifest in generators (and retailers) incorporating additional risk premiums in their prices, regardless of whether they also engage in the above conduct (bidding to avoid sunk costs, etc).
  - The heightened risks described above also have the potential to affect the degree of retail competition – particularly that offered by smaller retailers without ‘natural’ hedges. The proposal may mean that these types of businesses find it more difficult to enter the market and to expand once there.
31. For all of these reasons, the potential benefits associated with the proposal have been overstated and many of the costs understated or overlooked. The potentially substantial nature of these additional costs suggests that the methodology may in fact not offer any net efficiency benefits and may instead impose a net cost on the market, if it is introduced.

# 1 Introduction

32. This report has been prepared by the Competition Economists Group (CEG) on behalf of Transpower New Zealand Ltd (Transpower). Its purpose is to assist Transpower as it evaluates the Electricity Authority's (EA's) proposed revisions to the transmission pricing methodology (TPM). It provides a relatively 'high-level' review of the EA's paper<sup>13</sup> and comments from an economic perspective on the integrity of the analysis contained therein, and the conclusions consequently drawn.
33. We focus particularly on the proposed changes to the charging arrangement for the high-voltage direct current (HVDC) link and for interconnection assets.<sup>14</sup> The EA concludes that the HVDC charge is inefficient because:
- it discourages efficient investment in South Island generation, since it is only South Island-based generators that pay the charge;
  - it is not durable, since not all beneficiaries pay (e.g., North Island load) and, for those that do, charges do not necessarily equal private benefit; and
  - it encourages ongoing lobbying and reviews.
34. These observations are not new and are broadly accepted, e.g., the industry Chief Executive Officers' (CEO) Forum and the Transmission Pricing Advisory Group (TPAG)<sup>15</sup> each made similar points in their recent reviews of the TPM (see Appendix A). However, the EA's findings in relation to the interconnection charge – and its proposed solution – diverge considerably from the previous reviews.
35. The EA concludes that the interconnection charge is inefficient because it does not promote either efficient transmission investment, efficient peak demand reduction or the efficient location of major new load. It consequently proposes to reform this aspect of the TPM together with the HVDC charge by:<sup>16</sup>
- collapsing the distinction between HVDC and interconnection charges, i.e., treating the two assets as indistinguishable for pricing purposes;

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<sup>13</sup> Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012 (hereafter: EA Issues and Proposal Paper<sup>13</sup>).

<sup>14</sup> The interconnection charge relates to the high voltage alternating current (HVAC) network, excluding connection assets.

<sup>15</sup> The TPAG was formed as part of the EC review (the EA's predecessor).

<sup>16</sup> It also intends to make some adjustments to the connection charging arrangements to 'close loopholes' and to modify the arrangements for network reactive support services. We have not considered these aspects of the charging arrangements in this report.

- funding interconnection and HVDC transmission services through the loss and constraint rentals generated by spot market differentials throughout the grid<sup>17</sup> (a ‘**market-based**’ charge); and
  - because the loss and constraint rentals cannot fully fund the services in question (because of scale economies<sup>18</sup> and the understandable tendency to invest earlier rather than later<sup>19</sup>), it intends to recover the residual by:
    - setting prices for HVAC and HVDC assets based on its interpretation of a ‘beneficiaries pay’ pricing principle and applying those charges to off-take customers and generators alike (a ‘**beneficiaries pay**’ charge); and
    - recovering the remaining residual<sup>20</sup> from off-take customers (based on their contribution to regional coincident peak demand, or RCPD) and generators (based on their regional coincident peak injections , or RCPI), in a 50:50 split (an ‘**alternative charging option**’).
36. The methodology is based on the ‘hierarchy of approaches’ contained in the EA’s decision-making and economic framework paper.<sup>21</sup> However, rather than picking a single option, the EA attempts to ‘take what it can’ from each option, before moving to the ‘next rung’ in the ladder. The resulting methodology therefore contains a collection of different pricing principles. The proposed interconnection/HVDC charge is not a market-based, beneficiaries-pay, or a ‘postage-stamp’ price. Rather, it includes aspects of all of these principles.
37. Integral to the EA’s methodology is the Scheduling, Pricing and Dispatch (SPD) model that is currently used to determine prices and quantities at the 220 nodes in the wholesale market. It proposes to identify the beneficiaries of past (post May 2004) and future grid investments by applying the SPD model to selected assets and allocating the costs to beneficiaries in proportion to their share of private benefits. It

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<sup>17</sup> These rentals could accrue to Transpower or, in principle, to the owners of financial transmission rights (FTRs) for the infrastructure in question.

<sup>18</sup> There are strong economies of scale associated with new transmission investments because, once the land has been procured and the towers constructed, there is not much difference in cost between a high capacity line and a lower capacity line. This means that, once built, transmission lines eliminate congestion, and so any congestion rents.

<sup>19</sup> Given the importance of the transmission grid from a security of supply perspective, there is an understandable tendency to err on the side of prudence when constructing transmission lines and build earlier rather than risk the consequences of building too late.

<sup>20</sup> The EA recognises that there is likely to still be unrecovered costs even after parties are charged in proportion to their private benefit.

<sup>21</sup> Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Consultation Paper*, 26 January 2012 (hereafter: ‘EA Consultation Paper’) and Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Decisions and reasons*, 7 May 2012 (hereafter: ‘EA Decisions and Reasons Paper’).

intends to do so by comparing various wholesale market outcomes in which certain elements of the grid are removed.

38. If implemented, the proposal would represent a substantial departure from the existing TPM. We are not aware of any arrangements quite like it and, as we explain subsequently, the examples cited from other markets are not comparable. Transpower is therefore understandably interested in obtaining an independent review of the EA's analysis. We provide this in the remainder of this report, which is structured as follows:
- **section two** sets out some general observations on the proposal, including the way in which the EA applies its hierarchy of approaches, the timing of its proposal, the limitations of its quantitative cost-benefit assessment and the applicability of the cited precedent;
  - **section three** explains why the proposal is unlikely to reduce the scope for disputes and ongoing lobbying in the manner intended, and may instead lead to dynamic efficiency losses rather than dynamic efficiency gains;
  - **section four** explores the ways in which the proposal could compromise the efficiency of the wholesale spot market dispatch process by causing generators to adjust their bids so as to avoid the incidence of transmission charges, resulting in higher spot prices; and
  - **section five** explains why the proposal has the potential to amplify risk throughout the entire electricity supply chain and make life much harder for smaller retailers that do not have 'natural hedges'.
39. We have also set out some additional material in two appendices. Appendix A provides a brief history of transmission pricing in New Zealand, in which we recount the key findings of the several recent reviews that have been undertaken of the TPM. Appendix B contains a worked example from outside the transmission sector that illustrates the potential shortcomings associated with setting prices for a service based on a changing profile of beneficiaries.

## 2 General Observations

40. In this section we set out some general observations about the EA's overall approach and the analysis that it has undertaken to arrive at its proposed methodology. We consider the way in which it has applied its hierarchy of approaches, the timing of the proposed changes, the limitations of its cost-benefit assessment and the relevance of the precedent that it provides. We examine the more specific elements of the proposal in more detail in sections three to five.

### 2.1 Hierarchy of Approaches

41. The EA says that it has arrived at its methodology by working through the hierarchy of approaches contained in its earlier decision-making and economic framework papers. A number of the submissions pertaining to that paper questioned the practicality of the proposed framework. In particular, a recurring proposition was that 'market-based' and 'beneficiaries-pay' charges could have only limited application to transmission services.<sup>22</sup>
42. Most submitters appeared also to be under the impression that if a market-based charge, or a beneficiary- or causer-pays charge could not recover 100% of the costs of the relevant service then, under the EA's hierarchy, the 'next best option' would be considered. Most took that to mean that there was consequently very limited scope for such approaches to be applied to interconnection assets. However, the EA takes a rather different approach to selecting its preferred option in its latest paper.
43. The EA accepts that, for HVDC and interconnection assets, it cannot select any of its 'top three' choices in their own right. However, instead of 'going down the list' to an alternative charging option (such as the transitional postage stamp option favoured by the majority of the TPAG), it decides instead to implement each of its preferred approaches to the fullest extent possible. The resulting methodology therefore brings together a collection of different pricing principles, and is far more complex than the current TPM.
44. In our opinion, there is not necessarily any reason to think that some 'market-based' and 'beneficiaries-pay' charging is better than none – particularly if it involves bringing together a number of different pricing principles, as the proposal in question does. One must consider how the plethora of concepts that make up the interconnection charge will interact with one another, and the incentives this will create for the parties that they are levied upon.

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<sup>22</sup> The EA acknowledges this in its EA Decisions and Reasons Paper when it observed that: '...many raised issues about the application of the framework, with some suggesting that this implied the framework was unlikely to be practical'. See: EA Decisions and Reasons Paper, paragraph 9.

45. The fact that the pricing methodology will be applied largely to past investments makes this reconciliation even more critical. Because the proposal changes the allocation of sunk costs, it involves large wealth transfers and carries a risk of inefficient incentives and unwelcome distortions (which we explore in sections to come). Moreover, given that Transpower has just completed a new investment program, it would seem to be an especially inappropriate time to be contemplating major changes to that way in which those sunk costs are recovered.

## 2.2 Timing of the Proposal

46. The EA states (and we agree) that the TPM should focus on the overall efficiency of the electricity industry for the long-term benefit of electricity consumers. The achievement of this objective involves facilitating the efficient investment in and use of the grid, generation (including embedded generation) and demand-side management. The EA's reasons for revisiting the TPM and proposing the changes that it does are that:<sup>23</sup>
- over \$2 billion worth of transmission investment has been approved – by the EC before November 2010 and by the Commerce Commission since that time, including the HVDC pole 3 and the North Island grid upgrade – and the costs of those investments must be recovered under the TPM;
  - there have been significant changes to the regulatory framework, with the EA replacing the EC from 1 November 2010, and the function of approving major grid investments being transferred to the Commerce Commission; and
  - advances in technology and the reducing costs of computational power have made available more sophisticated means of allocating transmission costs.
47. In our opinion, setting aside the particulars of the proposal (which we consider subsequently), these do not seem to us to be compelling rationales for proposing a substantially different approach for setting HVDC and interconnection charges. The TPAG and the CEO Forum were cognisant during their reviews of the fact that simply reallocating sunk costs risks much for little reward (see Appendix A for more detail). In contrast, the EA's seems not to have given as much attention to this trade-off in formulating its proposal.
48. Moreover, now that Transpower has had over \$2 billion of investment approved (much of which is now completed), there is limited benefit from significantly changing the way those costs are recovered, since:
- the \$2 billion is, for all intents and purposes, a sunk cost;<sup>24</sup> and

<sup>23</sup> EA Issues and Proposal Paper, paragraph 2.3.9.

<sup>24</sup> It was also perceived to be beneficial and that assessment was made based on generation and load patterns forecast under the current TPM.

- the investment decisions have been made and there is no way now to reduce the associated fixed costs.

49. Looking forward, there are considerably fewer major new transmission investments on the horizon.<sup>25</sup> The EA appeared to acknowledge as much in its earlier decision-making and economic framework paper.<sup>26</sup> In examining an earlier proposal of the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) – a proposal that resembles in some important respects that which the EA has now proposed (see further discussion in Appendix A) – it observed that:<sup>27</sup>

*“[M]ost of the grid upgrade expenditure likely to be required in the next few years has already been approved by the Electricity Commission. As a result, adopting the approach of TWG would not have much impact on transmission charges for a significant period of time.”*

50. However, recalibrating the allocation of those sunk costs has the potential to provide inappropriate incentives and reduce static and dynamic efficiency, as we explain in the sections ahead. In other words, the benefits are unclear, but the potential costs are immediately evident. Orthodox economic principles suggest that because such a substantial sum has been invested recently by Transpower (and that future investment needs are far less extensive) it is a good time to *abstain* from making major changes.
51. In addition, it is not clear why the Commerce Commission assuming responsibility for approving grid investments should prompt substantial changes to the TPM. In fact, it heightens the risk of inconsistencies emerging between the two frameworks when the new grid approval process is just ‘bedding in’. Similarly, even if advances in computational power in recent years have indeed opened up new pricing options, more complex allocation methodologies are not necessarily superior.
52. For these reasons, we find it hard to escape the conclusion that, if one’s objective is to incentivise the efficient investment in and use of infrastructure, and a large investment program has been recently completed, re-pricing those assets is an intrinsically risky exercise. The potential efficiency gains are not obvious, but the potential costs are clear, as we set out in more detail in sections three to five.

<sup>25</sup> See: <https://www.transpower.co.nz/projects>.

<sup>26</sup> Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Consultation Paper*, 26 January 2012 (hereafter: ‘EA Consultation Paper’) and Electricity Authority, *Decision-making and economic framework for transmission pricing methodology review, Decisions and reasons*, 7 May 2012 (hereafter: ‘EA Decisions and Reasons Paper’).

<sup>27</sup> EA Consultation Paper, paragraph 4.3.17.

## 2.3 Cost Benefit Methodology

53. The Issues and Proposals Paper includes a variety of calculations that purport to demonstrate the relative costs and benefits of the various pricing options that have been considered. However, the \$173.2 million in net benefits said to be associated with the proposal is simply a product of the assumptions employed in its modelling. To arrive at the estimate, total sector revenue<sup>28</sup> (based on assumed growth rates) is multiplied by an ‘efficiency parameter’ (determined based on various qualitative information<sup>29</sup>) and a discount rate (of 6.01% real).
54. The efficiency factor that has been applied is 0.3% of total revenue. This is equivalent to a \$0.12/MWh (or 0.05%) reduction in the average unit price per MWh (over total volumes).<sup>30</sup> This efficiency factor is not estimated; it is *assumed*. Taking a lower (higher) parameter will reduce (increase) the estimated economic benefits. Similarly, applying a *negative* parameter will result in a net economic *cost*. The magnitude of this parameter is ostensibly justified through a series of qualitative assessments. However, none of these analyses can provide any real insight into the appropriateness of the assumption.
55. The first assessment that is undertaken is a comparison between the assumed efficiency parameter and the long run total factor productivity (TFP) growth rate that has been applied by the Commerce Commission to determine the default price-quality paths for electricity distribution businesses. However, these two factors are not measuring the same thing and the comparison therefore cannot reveal anything meaningful about the robustness of the assumed efficiency parameter.
56. An examination is then made of the metrics contained in reports by the Electric Energy Market Competition Taskforce and PA Consulting. However, these also are of questionable significance, since they are, again, measuring quite different things. The ‘avoided generation cost’ example is also unhelpful. The example suggests that if the proposal avoids significant future generation costs, then its benefits will exceed those implied by the efficiency parameter. However, if those costs are not avoided (and no material is presented to show why they would be), or if future generation costs are higher, then the opposite will be true.
57. The EA is quite correct that measuring efficiency benefits is difficult. It is also the case that New Zealand courts have accepted similar approaches in the past – albeit in different contexts. However, neither of these points detract from the basic problem that there is no principled basis for the efficiency parameter or, in turn, for

<sup>28</sup> The size of the electricity market is estimated by multiplying each sector’s volume (i.e., industrial, commercial and residential) by its final price. Market prices are expressed in constant 2011 dollars. *See*: EA Issues and Proposal Paper, Appendix F, paragraph 3.12.

<sup>29</sup> EA Issues and Proposal Paper, Appendix F, paragraph 3.7.

<sup>30</sup> EA Issues and Proposal Paper, Appendix F, paragraph 3.15.

the purported quantum of benefits. The 0.3% value simply reflects the EA's belief that its proposal will deliver significant economic benefits when, for the reasons we set out in sections three to five, there is good reason to think that it will not.

## 2.4 Appeal to Precedent

58. The EA states that the beneficiaries-pay approach to transmission charging is emerging as 'common practice' internationally. It cites four examples to support this proposition: a recent decision of the US Court of Appeals in the PJM market, and arrangements for approving grid investments in Argentina, New York and New Zealand. In our opinion, four cases do not establish a 'common international practice' and, even if they did, the examples bear little resemblance to what has been proposed.
59. The US Court of Appeal in the PJM matter ruled that the regulator (FERC) should not have required grid users to pay prices for new investments that exceeded significantly the private benefit they obtained. However, a defining characteristic of the proposal in this instance is the application of a beneficiaries-pay principle to *past* (as well as new) investments. If anything, Justice Posner cautioned against reallocating sunk costs in this manner in his judgment. This is evident in the following extract, which we have reproduced in its entirety:<sup>31</sup>

*“PJM wants that transmission to be priced on the basis of the cost to American Electric of transmitting one more unit of electricity, that is, the marginal cost; and FERC agrees. Such a price excludes the cost that the company incurred when it built the transmission facilities. That cost – which American Electric wants to be permitted to reflect in its rates – is what economists call a “sunk” cost, that is, a cost that has already been incurred. So while its financial burden can be shifted (from American Electric to the eastern utilities), the cost itself cannot be shifted, and therefore shifting the financial burden created by the cost from one set of shoulders to another will have no direct effect on service or investment.*

*Had FERC decided that American Electric would not be permitted to charge a price that covered the cost of building a new transmission facility or upgrading an existing one, its decision would have affected the allocation of resources and not just money. It would have deterred the building of new facilities that benefited customers outside American Electric's service area, because building them would become an unprofitable venture. FERC emphasizes, however, that the company's existing facilities, which are all that are involved in this case, were built before 2001 when PJM became a Regional Transmission Organisation, and were intended to serve American Electric's customers only. So even if the facilities had not been fully paid for,*

<sup>31</sup> *Illinois Commerce Commission v FERC*, 576 F.3d 470, 476, pp.2-3.

*there would be no economic basis for shifting any part of the costs to other members, because American Electric did not expect when it built the facilities that any part of their cost would be defrayed by anyone besides its customers.”*

60. The preceding paragraph serves to highlight the basic problem that beneficiaries change over time. It is one thing to look, as the court did, at the beneficiaries of a new investment and make a judgement at that time about the relativity of prices and benefits at a particular point in time. It may even be possible to ‘lock-in’ the prices that will apply to a new investment at the time that it is made, based on the then current profile of beneficiaries.<sup>32</sup> However, applying a ‘beneficiaries pay’ approach to set prices for *past* investments is an altogether different proposition.
61. The EA’s proposal is to charge parties based on who is perceived to be benefiting from (past and present) interconnection and HVDC assets *today*. That is not what the court is suggesting should be done. If one were to attempt such an exercise, the above passage suggests that the relevant question would not be “who are the beneficiaries now?” but; rather, “who were the beneficiaries expected to be at that time over the life of the assets?” Even if that exercise were possible (which is unlikely<sup>33</sup>), it would not be advisable.
62. Indeed, like the TPAG and the CEO Forum (see appendix A), Posner acknowledges that, although the financial burden of a past sunk cost can be shifted from ‘one set of shoulders to another’, the cost itself is unavoidable, and the reallocation will have no direct effect on service or investment. In other words, the judgment appears to be cautioning against what has been proposed in relation to interconnection and HVDC charges.
63. The other examples are also inapposite. Between 1992 and 2001, major transmission expansions in Argentina were subjected to a ‘vote’ and, before they could proceed, at least 30% of the beneficiaries were required to support the proposal and no more than 30% of the beneficiaries could be opposed. A similar regime exists in New York, where a regulated transmission investment requires the support of a supermajority (80%) of beneficiaries. One can debate at length the merits of these arrangements,<sup>34</sup> but the essential point is that these are all examples of different ways to decide/fund *new* transmission investments:

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<sup>32</sup> For example, see: Hogan, WW, *Transmission benefits and cost allocation*, Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011. As we explain in more detail in section four, this requires difficult long-term judgements to be made about future grid use patterns and investments, etc.

<sup>33</sup> The substantial problems associated with such an exercise are described in more detail in section 4.1.

<sup>34</sup> The EA cites a paper that argues that the Argentinean arrangements were a success, but many other commentators have deemed them a failure. For an overview of these critiques, see: Littlechild, SC and Skerk, CJ: “Regulation of transmission expansion in Argentina Part I: State ownership, reform and the fourth line”, CMI EP 61, 2004, p.5.

- none of the arrangements mentioned above involve reallocating the sunk costs of past investments in the fashion contemplated by the proposal; and
  - more generally, we are not aware of any transmission pricing arrangements that do so and it is not a foreseeable trend.
64. The methodology developed by the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) is also not relevant. First, like the Argentinean and New York examples, the proposal related only to new investments – it did not involve reallocating the sunk costs of past investments. Second, as we explain in more detail in Appendix A, the proposed arrangement was *rejected* by a majority of the industry in 2002 and, when the *Electricity Governance Rules* (which contained the regulatory TPM) were introduced in 2003, an administrative process was favoured.
65. It has therefore not been established that the proposal is consistent with common international practice, or even a foreseeable trend. None of the examples cited involve the reallocation of sunk costs – if anything, the US Court of Appeal decision appears to caution against the practice. Moreover, the New Zealand TWG EGEC example is a case study in which the majority of the industry and the government of the day rejected a proposal to apply a market-based approach to undertaking new transmission investments, favouring instead an administrative process.

## 3 Greater Potential for Disputes

66. In this section we illustrate why we believe that the proposals are unlikely to reduce the scope for disputes and lead to a more efficient investment process. In our opinion, the opposite outcome is more probable. Specifically, the proposed approach for establishing interconnection charges is likely to broaden the scope for disputation and harm dynamic efficiency.

### 3.1 Rationale for the Proposal

67. Before Transpower can undertake a major new capital investment, it must satisfy the Investment Test set out in its Capital Expenditure Input Methodology (IM), administered by the Commerce Commission. To meet that test, a proposed investment must (amongst other things), have the highest 'expected net electricity market benefit'.<sup>35</sup> The focus is therefore on ensuring that new investments maximise the net market (as opposed to private) benefit. The Grid Investment Test (GIT) previously administered by the EC had an equivalent emphasis.
68. It has not suggested (at least not explicitly) that this IM is incapable of delivering the right investment outcomes. There also appears to be no suggestion that Transpower has, in the past, built 'the wrong assets at the wrong times'.<sup>36</sup> Rather, the proposal is ostensibly targeted at the *process* by which investment decisions are made. It has been contended that, under the current manifestation of the HVDC and interconnection charges, some parties may have weak incentives to advocate for/against only efficient/inefficient transmission investments.
69. This is said to be because there is no direct and proportionate link between the beneficiaries of an investment (i.e., the parties most likely to agitate for it) and the parties that pay for it. This, in turn, is claimed to lead to ongoing lobbying, contention amongst industry participants and the inefficient use of, and investment in, transmission assets. For this reason, even if the right investment decisions are ultimately made (and no material is presented to suggest that this has not been the case), time and money is still wasted on lobbying and disputation.
70. The EA suggests that its SPD-based methodology will be a durable way of identifying and levying private beneficiaries that will reduce disputes and prevent the beneficiaries of an uneconomic project from lobbying for it to proceed simply because the costs will be smeared across other users. It therefore contends that its

<sup>35</sup> Commerce Commission, *Re Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, 31 January 2012, Schedule D1, p.53.

<sup>36</sup> For example, the EA does not seem to question directly the efficiency of the \$2 billion in investments that was approved recently.

proposed interconnection charge will promote dynamic efficiency.<sup>37</sup> The source of those efficiency benefits is not necessarily ‘better investment outcomes’ (as noted above, the outcomes may ultimately be the same) but, rather, a superior investment *process* that avoids the costs of disputes.

71. It is certainly true that if parties know they will be required to pay a price for a new asset that is proportionate to their expected private benefit, they will have an incentive to advocate for the right investments at the right time. Moreover, for certain types of transmission assets a ‘causer’ or ‘beneficiary’ pays approach is relatively straight forward to put in place. Connection assets are an example. If a generator wishes to connect to the grid and will be the only party using the asset, it will be only be prepared to fund the investment through connection prices if its private benefits exceed the costs it will face.
72. However, even with connection assets, complexities can arise over time if there is a non-zero probability that other parties will connect and ‘share’ existing assets. For instance, if a second generator comes onto the scene several years later and wishes to connect to an existing spur, the marginal cost of hooking up that second-mover may be very low. This raises a number of difficult questions:
  - Should the second-mover, which is now clearly benefiting from the transmission line, pay a price that reflects the marginal connection cost or should it be required to pay a greater share of the sunk costs – thereby reducing the burden on the first mover?
  - If the latter, should the first mover have the ability, within defined regulatory bounds, to negotiate the level of contribution made by second movers, recognising that this will impact on the incentives for the initial investment and/or subsequent investments?
73. These are not straightforward issues and serve to highlight one of the greatest challenges with applying causer- and beneficiaries-pays principles to transmission assets. That is that the benefits of transmission investments are spread over time and often in a complex fashion. Today’s beneficiaries may not be tomorrow’s. In its report to the CEO Forum, NERA observed that,<sup>38</sup> although the current connection charging approach provides a locational signal to connecting parties of the costs of their decisions – albeit an imperfect one – the potential for distortions remains:<sup>39</sup>

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<sup>37</sup> As we noted above, this belief appears to be one of the central reasons for adopting the 0.3% efficiency parameter in its cost-benefit analysis that yields the estimated \$173.2 million in net economic benefits (in NPV terms over 30 years).

<sup>38</sup> The potential complications arising from these issues are canvassed in some detail in the NERA report prepared for the CEO Forum, *see*: NERA Report, pp.44-54.

<sup>39</sup> NERA Report, p.54.

*“[B]ecause connection charges can vary substantially depending upon the type of generation that is built and its location, regardless of the net market benefits, inappropriate investment signals can be created in some circumstances. In addition, the arrangements for recovering the costs of ‘shared’ connection assets may give rise to significant step-changes in connection charges as ‘beneficiaries’ change over time, which can reduce certainty and further harm dynamic efficiency.”*

74. In other words, it is challenging even to apply causer- and beneficiaries-pays principles to connection assets. These difficulties are exacerbated considerably if one seeks to apply a beneficiaries-pay principle to interconnection (and HVDC) assets in the manner proposed. Investments in such assets exhibit long lives, significant economies of scale and substantial interdependencies with existing interconnection assets (it is, after all, a ‘shared grid’). It is a complex and controversial exercise to identify the beneficiaries of such assets at a *point* in time, much less over their entire lives, during which time the nexus of benefits can change dramatically.
75. However, if one were to attempt such an exercise there are, broadly speaking, two ways of going about it. The first is to seek to identify who the beneficiaries are *expected* to be over the life of an asset and to ‘lock-in’ the charges over the period to recoup the investment costs. The second is to perpetually change the profile of charges as beneficiaries change over time – this is the approach that has been proposed. As we explain below, neither approach would be likely to reduce materially the costs of disputes in the manner intended.

### 3.2 ‘Locked-in’ Beneficiaries

76. The first way to apply a ‘beneficiaries-pays’ approach to pricing an interconnection asset is to estimate the expected future private benefits to parties over its life – measured at the point in time at which the investment is made. The resulting charges are then ‘locked-in’, so that the beneficiaries identified at that particular reference point continue to pay those prices over the lifetime of the asset (the parties might also be issued FTRs or some form of property right in return for the funding).<sup>40</sup> The quantum of private benefits might be forecast using transmission planning and dispatch models.
77. Hogan (2011) suggests such a methodology – although only for *new* transmission investments.<sup>41</sup> The principal advantage of such an approach is that, by fixing the

<sup>40</sup> Issuing FTRs would present an array of additional practical challenges that would need to be overcome. A summary of the steps that would need to be undertaken to introduce FTRs is provided at pages 105 to 106 of the NERA Report.

<sup>41</sup> Hogan, W. W, *Transmission benefits and cost allocation*, Mossavar-Rahmani Center for Business and Government, John F. Kennedy School of Government, Harvard University, May 31, 2011.

charge in advance of the investment, parties cannot alter their behaviour to avoid the charge, which promotes static efficiency. However, even if this (or a similar) methodology is limited to new investments, several drawbacks exist – some of which are highlighted in the Issues and Proposals paper,<sup>42</sup> including:

- it is impossible to forecast with any real precision the temporal dynamics of private benefits over the 30-50 year (or thereabouts) life of an interconnection asset – any such exercise would swiftly become a ‘battle of competing models’, as parties sought to demonstrate that they were not going to benefit to the degree forecast by the transmission planner; and
- because parties’ actual benefits may differ from their anticipated benefits, they may end up paying for assets from which they do not benefit, which is likely to make them more likely to agitate against investments from which they may very well benefit, simply because they fear the possibility of being subsequently burdened with a disproportionate share of the costs.<sup>43</sup>

78. For these reasons, even if this (or a similar) approach is applied only to *new* investments in interconnection assets, the potential for distortions is considerable. This would be unavoidable given the fact that this assessment would decide “once and for all” who was going to pay for the asset.
79. Seeking to apply the approach to *past investments* would entail even more controversy. If one were to attempt such an exercise (which is clearly not intended), it would be necessary to look back at every investment since May 2004 (the cut-off date proposed by the EA) and ask: “who were the beneficiaries expected to be over the life of that asset *at the time that the investment was made?*” This would be a complex (perhaps impossible) thought experiment.
80. Moreover, it is not clear what such an exercise would achieve since, as we have explained, shifting the financial burden of past sunk costs does not offer any obvious efficiency benefits, and risks giving rise to unintended consequences. In other words, locking-in prices for a defined class of beneficiaries over the life of an investment is a fraught exercise that would increase scope for disputes and risk many distortions.
81. The proposed methodology might be thought of as addressing these problems by putting in place a process that continually revisits the estimation of the beneficiaries as circumstances change over time. One might expect that this would therefore remove some of the uncertainty and controversy that would be associated with the “one off” estimation of beneficiaries. However, that is unlikely to be the case.

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<sup>42</sup> EA Issues and Proposal Paper, paragraph 6.5.5.

<sup>43</sup> *Ibid.*

### 3.3 Ever-changing Beneficiaries – the Proposed Approach

82. The proposed methodology seeks to identify the beneficiaries of past (post May 2004) and future grid 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 postulating various hypothetical wholesale market outcomes in which certain elements of the grid are removed. In this way, the identity of beneficiaries – and the prices that they pay – will *vary over time* as grid usage patterns change and new investments are made.
83. It is suggested that charging a changing pool of beneficiaries represents the most efficient means of applying the ‘beneficiaries pay’ principle. It is said that the methodology will be more durable and subject to less controversy, because the charges applied to parties for interconnection assets will reflect the benefits that they obtain from investments over time. This will ultimately promote the more efficient use of and investment in transmission grid infrastructure.<sup>44</sup>
84. However, beneficiaries will only have an incentive to lobby for an investment if their incremental benefits exceed the incremental total grid costs that they will be allocated. Mathematically, the methodology will provide beneficiaries with efficient incentives to agitate for/against new investment if:

$$\text{PV of expected change in transmission charges for party } i \text{ consequent on investment} = \text{PV} \frac{\text{E}(\text{benefits of the investment to party } i)}{\text{E}(\text{total benefits of the investment})} \times \text{E}(\text{investment cost})$$

85. It is true that, compared to the ‘one-off’ approach described above that the proposed approach avoids a highly controversial *initial* modelling exercise to determine, once and for all, who the beneficiaries of a new investment will be. However, that does not reduce or remove the uncertainty and controversy associated with deciding who the beneficiaries are; it simply spreads it through time. In doing so, it creates uncertainty for participants because they do not know how the results of those future modelling exercises will turn out. We elaborate below.

#### 3.3.1 Incentives Created by Sunk Costs

86. The price of avoiding the initial controversy associated with a ‘one-off’ assessment is the incentives potentially provided to users to lobby for inefficient investments or against efficient investments. This is because spreading the assessment of beneficiaries through time has the effect of turning transmission pricing into an

<sup>44</sup> EA Issues and Proposal Paper, paragraph 18.

allocation of sunk costs. Under such an approach, once a new asset is built, this will tend to change the way in which market participants pay for all of the other interconnection assets that have been built since May 2004. For example:

- Imagine the grid comprises only two interconnection assets – A and B. The beneficiaries of asset A (and the prices for using that asset) will be derived by postulating a world without it – i.e, a grid comprising only asset B. Similarly, charges for B are derived by imagining a world in which A is the only asset.
- However, when new asset ‘C’ is built, the prices for asset A are now determined by postulating a world in which the grid comprises not just B, but B *and* C. Likewise, charges for B are set by hypothesising a world in which A and C are the only grid elements.
- The interconnected nature of the grid and the interdependency of its elements mean that there is no reason to think that the beneficiaries of A and B will be the same before and after C is built – there might be a substantial difference (and this may also change over time).
- This means that the existing market participants may lobby for or against the construction of asset ‘C’ for reasons that have nothing to do with the direct costs and benefits of the bespoke investment but, rather, because they will become ‘larger’ (or ‘smaller’) beneficiaries of another part of the grid.

87. It follows that, if the proposal is implemented, parties can be expected to view every new investment decision not simply on the basis of the direct costs and benefits of the asset in question (consistent with the above formula), but on the basis of how it will affect their estimated benefits of every other part of the grid, and so the totality of their interconnection charges. Specifically, the commercial benefits of new interconnection asset ‘N’ to an industry participant will depend upon:

- the impact that investment N is likely to have upon the prices it pays/receives for electricity; *less*
- the estimate of its share of the costs of investment N that will come out of the private beneficiaries test; *less*
- the change in its allocation of the cost of investments ‘N-1’, ‘N-2’, ‘N-3’ and everything that has come before (dating back to May 2004) or can be expected in the future.

88. The \$173.2 million in net economic benefits thought to flow from the proposal is predicated, in large part, on a belief that the first two factors above will incentivise parties to advocate only those new investments for which their private benefits exceed the costs they will face. This is said to remove the incentive for parties to lobby for projects that benefit them only because others will pay for them. However, participants will also have commercial incentives by virtue of the third factor, which involves changes in allocations of sunk costs.

89. Reallocating sunk costs cannot provide efficient incentives to parties to support or oppose new transmission investments. Yet, over time, the quantum of sunk investments subjected to the methodology will grow to include the entire interconnected grid. Indeed, the ‘post-2004 assets’ already comprise a significant proportion of the total grid value. It is therefore conceivable that the impact of the third factor will be larger than that of the first two. Appendix B illustrates this using an example from outside the transmission sector.
90. For these reasons, it is unlikely that the proposal will reduce the resources spent on lobbying and reviewing the methodology in the manner envisaged. Rather, it seems plausible that the nature of the transmission grid will mean that there will be even greater scope for disputes. Moreover parties may advocate against efficient investments (or for inefficient investments), not because of the private costs and benefits of the new investment in question, but because they care primarily about the allocation of sunk costs. Disputes will also arise in relation to model inputs.

### 3.3.2 Potential for Disputes over Model Inputs

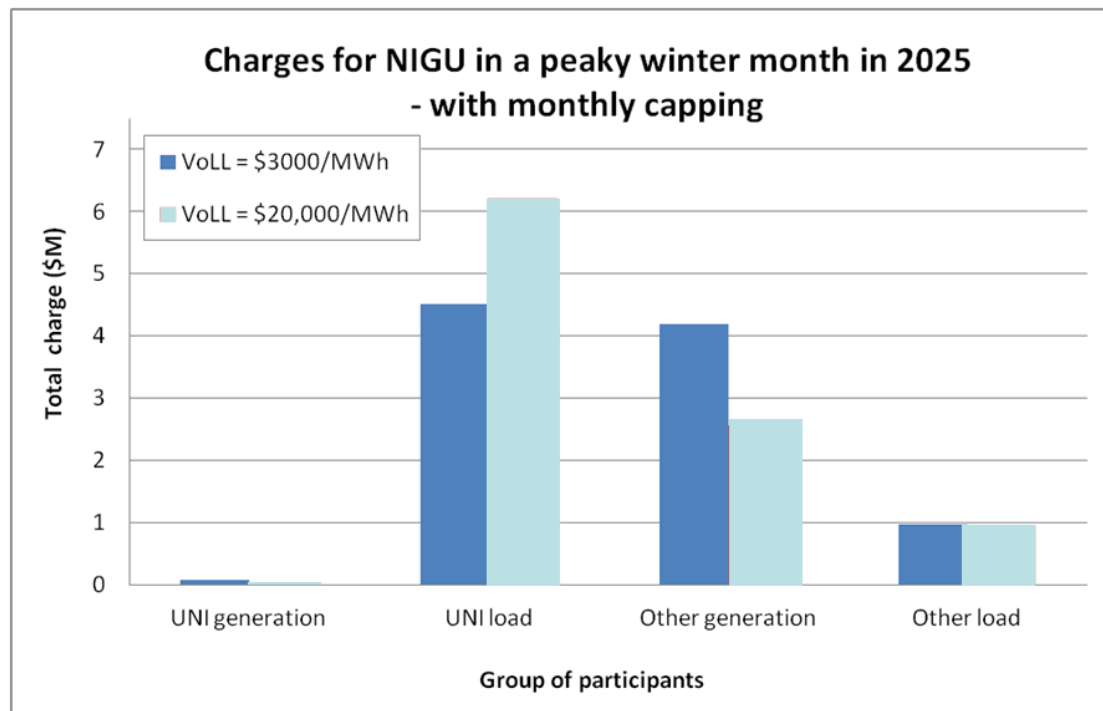
91. Because the interconnection charges that parties will pay will vary over time based on wholesale market outcomes, it is natural to expect that parties will agitate for the SPD model to be changed in ways that reduce their costs. Of particular relevance here are the myriad inputs to the SPD model that have a significant effect on the incidence of charges, but which require a material degree of subjective judgement. These parameters can be expected to attract particular scrutiny and controversy if the proposal is implemented.
92. For example, charges appear to be quite sensitive to the value that is assigned to unserved demand – the ‘value of lost load’ (VoLL), i.e., the value that customers place on network reliability. This input can have a significant effect on the assumed incidence of private benefits once the SPD model starts postulating the removal of particular grid elements. If taking away part of the grid during a half-hour period would have resulted in some customers not receiving electricity, their ‘private benefits’ (and the interconnection charges that they must pay) depend largely upon the costs they are assumed to avoid by the transmission asset being there.
93. It follows that, if a higher \$/MWh cost is assigned to VoLL, this will result in load in an ‘importing region’ paying higher interconnection charges.<sup>45</sup> Transpower has undertaken some preliminary modelling to test the sensitivity of charges to changes in VoLL. Those results are reproduced in Figure 1 below. The figure shows that increasing VoLL from \$3,000 to \$20,000/MWh may significant re-align the

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<sup>45</sup> As VoLL increases, so too does the private benefit that consumers are assumed to derive from a particular transmission network element, since the existence of that asset may allow them to avoid those higher costs of unserved demand during peak periods.

charges. During a ‘typical’ peaky winter month in 2025, load based in the upper north island is estimated to assume a greater proportion of transmission costs.

**Figure 1 Incidence of Charges with Different VoLL Parameters**



Source: Transpower, Electricity Authority TPM Proposal (2012) – Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.13.

94. The problem with this sensitivity is that there is no ‘unambiguously correct’ value for unserved demand – there is significant scope for legitimate disagreement. Views may differ not only as to the value itself but also to the circumstances in which it may be appropriate to use a higher (or lower) estimate. For example, if the cost of additional local generation is to serve as a proxy for VoLL, it will be necessary to make an assumption about the *type* of plant that will (hypothetically) be called upon to generate, for example:
- if the removal of a certain grid element would result in unserved demand in only a few trading periods per year, it may be appropriate to assume that, say, a new diesel peaking plant would otherwise meet that demand; but
  - if eliminating the asset would precipitate unserved demand in a significant number of periods per year, a point may come where it is more appropriate to assume that demand will be met by new base-load plant.
95. These assumptions have a significant effect on the incidence of charges, but require a considerable element of judgement. Moreover, the value of un-served demand is not the only model input that exhibits these properties – several other parameters

display similar sensitivity.<sup>46</sup> Parties can therefore be expected to continually agitate for these aspects of the SPD model to be changed, because they know that even a small revision in their favour may significantly reduce their charges.

96. It would certainly be possible to ‘fix’ these parameter values in advance for a period, e.g. five (perhaps even ten) years. However, that is unlikely to satisfactorily address the matters described above. In our opinion, locking-in parameter values would neither eliminate the potential for disputes, nor reduce the level of controversy relative to the existing TPM, because:
- there would inevitably be significant dispute over the initial values assigned to these parameters, and the values assigned at each subsequent review – given the potential value at stake, those disputes could conceivably culminate in costly litigation (such as judicial reviews);
  - because the SPD model would have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative model), there would be a wider ‘potential set’ of parameters over which there would be controversy when the TPM was set/revisited; and
  - the fact that the current TPM has been ‘set’ for a prolonged period has not insulated it from ongoing controversy, and so there is no reason to think that ‘locking-in’ VoLL, the capping period and so on would prevent parties from constantly lobbying to have those parameters changed.
97. Moreover, even if fixing parameter inputs in advance was an effective solution (which it is not), it is simply not possible to lock-in every value. That is because occasions would arise when the SPD model could not be ‘solved’ with those values – this is invariably the case with sophisticated quantitative models. Transpower will therefore need to have the flexibility to exercise its judgement when defining counterfactuals in order to produce a vector of prices. The nature and effect of these judgements may vary based on many factors, including the level of demand and other grid constraints. This is a recipe for ongoing controversy.
98. If Transpower must make a ‘judgement call’ during a trading period in order to ‘solve’ the model, there is a good chance that there will be ‘winners and losers’ (this is frequently the case with transmission pricing). Whenever a party finds itself on the ‘wrong end’ of a judgement that could have gone either way, it can be expected to challenge that decision (provided the sum in question is not trivial). Moreover, because the SPD methodology will eventually apply to most of the grid, the frequency of disputes – and the sums at stake – will increase over time.

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<sup>46</sup> The time period that is used to estimate benefits is one such example. This also calls for a material degree of subjective judgement and Transpower’s preliminary modelling reveals that charges may vary significantly depending upon whether benefits are ‘capped’ on a monthly or half-hourly basis. See: Transpower, *Electricity Authority TPM Proposal (2012) – Transpower’s Modelling Work SPD, EA Modelling Workshop, Auckland, 4 December 2012, p.12.*

99. Finally, it is worth recognising that such lobbying may not necessarily be limited to debates over parameter values or incremental changes. If the proposed methodological changes are made, this may signal a willingness to make widespread changes to the TPM. Industry participants may therefore be emboldened to propose entirely new pricing methodologies that (inevitably) favour their own interests. Given the substantial wealth transfers typically involved in such methodological changes, the potential upsides would be difficult to ignore – particularly as the proportion of the grid subject to the methodology expands.

### 3.4 Summary

100. The proposed methodology is unlikely to reduce the future costs of disputes or promote more efficient investment outcomes. In our opinion, the more probable outcome is that the proposal will significantly increase the controversy surrounding new investments and ongoing interconnection prices. Moreover, participants may be motivated by factors that cause them to act in ways that compromise dynamic efficiency, particularly, the desire to avoid being allocated sunk costs.
101. Parties can also be expected to perpetually agitate for changes to be made to the way that the methodology is implemented or, potentially, for it to be replaced with an alternative approach that favours their own interests. Parties will also have an incentive to challenge any instances in which Transpower must make an unfavourable ‘judgement call’ in order to ‘solve’ the SPD model. The result is a recipe for ongoing controversy.

## 4 Potential for Inefficient Grid Use

102. In this section we explore the ways in which the proposal may reduce the efficiency of the wholesale spot market dispatch process by causing generators to adjust their bids so as to avoid the incidence of transmission charges. However, before doing so, it is instructive to reflect briefly upon the incentives that exist currently. We therefore begin by briefly describing the New Zealand wholesale market arrangements and the RCPD-based interconnection charges presently levied on off-take customers.

### 4.1 Status Quo

103. Currently, all generators pay connection charges and South Island generators pay HVDC charges that are more or less fixed.<sup>47</sup> Their expected transmission charges have little, if any bearing on their wholesale bids. Rather, the wholesale market design is directed towards promoting competition between generators that produces prices that reflect their short-run marginal costs (SRMCs). Although generators are permitted to offer their capacity at any price, the existence of competing offers normally<sup>48</sup> constrains the 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);<sup>49</sup> and
- 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.

104. It follows that anything that *adds* to the SRMC of operating generation plant will be reflected in wholesale offers and may compromise the efficiency of the dispatch process. It was this potential for wholesale market distortions that caused Transpower to impose a peak charge to recover HVDC costs.<sup>50</sup> In particular, it

<sup>47</sup> Although, as the EA has recognised, the HAMI charge does sometimes result in certain generating units ramping down their output in order to avoid contributing to their HAMI. Recall that generators do not pay interconnection charges.

<sup>48</sup> For example, a base load plant 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: NERA Economic Consulting, *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.

<sup>49</sup> For hydro plants, this will include an endogenously determined opportunity cost of water.

<sup>50</sup> Transpower, *HVDC Sunk Cost Recovery Pricing Methodology*, 19 April 1999, p.11.

recognised that if it levied HVDC charges based upon \$/MWh dispatched (an ‘energy-based’ charge) this would increase the opportunity cost of generating, and may result in higher wholesale prices.

105. This is because, to a South Island generator, a \$/MWh HDVC charge is the economic equivalent of an additional variable cost, such as fuel. If a generator’s ‘true’ variable cost was \$30/MWh,<sup>51</sup> and an energy-based HVDC charge added, say, \$2/MWh, then it would never bid less than \$32/MWh. This is distortionary, since the HVDC charge relates to the recovery of a sunk cost, i.e., whenever the market price was between \$30 and \$32/MWh, dispatch would not be least cost. The HAMI-based parameter mitigates this inefficiency (albeit imperfectly).
106. Presently, generators do not pay interconnection charges. Rather, the costs of the interconnection assets are recovered from off-take customers (distribution companies and transmission-connected customers) based on their respective contributions to ‘regional coincident peak demand’ (RCPD) in the region in which they are located. There are four such regions – the upper and lower North Island (UNI/LNI) and the upper and lower South Island (USI/LSI). A different approach is adopted across those regions:
  - in calculating the average RCPD in the UNI and USI regions, 12 peak demand periods are used; and
  - in calculating the average RCPD in the LNI and LSI regions, 100 peak demand periods (N=100) are used.
107. Interconnection charges for each customer are then calculated by multiplying the uniform interconnection rate<sup>52</sup> (price) by each customer’s average off-takes at times of RCPD. Because the average RCPD is calculated over 12 peak demand periods in the UNI and USI regions this provides off-take customers with an incentive to shift load to non-peak times so as to minimise their annual interconnection charge. Indeed, if an off-take customer does not reduce its contribution to the 12 peak demand periods, and other customers do, then it will pay a larger annual interconnection charge.
108. In contrast, there is not the same incentive to reduce load in the LNI and LSI regions, because it is far more difficult to control 100 peaks. The current arrangements therefore reflect a trade-off between recovering the sunk interconnection costs, while minimising distortions to consumption in the LNI/LSI regions and providing an incentive to off-take customers in the more congestion-

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<sup>51</sup> Noting again that, for hydro plants, this will include an endogenously determined value of water.

<sup>52</sup> The interconnection rate (or ‘price’) per kW used to determine off-take customers’ annual interconnection charges is the same for all customers in all locations and is calculated by dividing the required interconnection revenue by the sum of the average of the RCPDs for all customers.

prone UNI/USI regions times to reduce demand during peak times to improve the efficiency of grid usage decisions.<sup>53</sup>

109. Because generators do not currently pay interconnection charges, and HVDC charges are levied on the basis of HAMI, wholesale bids can normally be expected to reflect the operating and maintenance costs of the relevant plant.<sup>54</sup> The profile of generation will therefore typically reflect an SRMC-based merit order, resulting in efficient, least-cost dispatch. The incentives created for efficient least-cost dispatch is a defining feature of the New Zealand wholesale market, and is a key reason that it is widely acknowledged as being at the forefront of international best practice.<sup>55</sup>
110. If the proposal is implemented, generators will face two more variable transmission costs, which they can be expected to factor into their bids. Specifically, a generator will consider:
  - their short run operating and maintenance costs, such as fuel, labour, and so on (this might be characterised as its ‘true’ SRMC);
  - the quantum of interconnection charges that it expects to pay by being deemed a ‘private beneficiary’ of various parts of the shared grid; and
  - potentially,<sup>56</sup> the interconnection charges it expects to pay based on its contribution to the regional coincident peak injection (RCPI) in its location.
111. The second and third factors have the potential to differentially affect generators such that the ‘aggregate industry SRMC’ does not reflect the ‘true SRMC’. This could reduce the efficiency of the wholesale market and the way in which the transmission grid is utilised. In particular, these charges risk compromising the efficiency of the wholesale market and unwinding some of the benefits of the existing RCPD charging arrangements. We explain their potential effects below, beginning with the incentives that might be created by the new ‘beneficiaries pay’ charge.

## 4.2 ‘Beneficiaries-Pay’ Charge

112. If transmission charges were to be levied upon generators in the manner envisaged by the EA, this will increase the opportunity cost of generating, and may result in higher wholesale prices. This is because, like the \$/MWh charge discussed above, the ‘private benefit’ based charge is the equivalent of an additional variable cost. A

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<sup>53</sup> Like the wholesale market arrangements, the RCPD charge is also generally viewed as being a positive feature of the New Zealand arrangements, *see*: NERA Report, pp.23-24.

<sup>54</sup> For hydro-plants this will also include an endogenously determined value of water.

<sup>55</sup> For example, *see*: Hogan, W. W, ‘Electricity Market Restructuring: Reforms of Reforms’, *20<sup>th</sup> Annual Conference, Center for Research in Regulated Industries*, Rutgers University, 25 May 2001, pp.22-23.

<sup>56</sup> As we explain below, the extent to which generators will take this into account depends to a large extent upon the number of periods over which the RCPI charge is recovered.

generator can therefore be expected to take that additional expected cost into account when formulating its wholesale bids.

113. This, in itself, need not reduce the efficiency of the generation sector if all generators' costs are more or less equally (proportionally) increased.<sup>57</sup> In those circumstances, the SRMC 'curve' would 'shift up' but its 'shape' would not be affected. However, in reality, different generators will be affected differently by the proposal – such that both the level and the shape of the SRMC curve will be distorted. The net effect will be that some generators are dispatched when they have a higher 'true' SRMC than other generators not dispatched.
114. The methodology might also cause generators to modify their wholesale bids in order to avoid being deemed 'beneficiaries' of certain parts of the transmission grid and paying transmission charges to recover those sunk costs. A specific example contemplated in the Issues and Proposal paper is that South Island generators might try to avoid the 'beneficiaries-pay' charge for Pole 3 of the HVDC by formulating their bids in such a way that they are seen collectively only to be using Pole 2 of the link. This scenario is postulated at paragraph 38 of the paper:<sup>58</sup>

*“If successful, the revised offering behaviour would reveal that pole 3 was not economically justified and doesn't deliver private benefits to South Island generators. The costs of pole 3 in this case should be recovered from consumers receiving private benefits from pole 3 (if any) or through the residual charge in a way that is analogous to a 'broad base low rate' tax on generators and consumers for uneconomic grid investments; and*

*Alternatively, if South Island generators were unable to structure their offers to avoid the beneficiaries-pay charge, this suggests pole 3 delivers private benefits to them, and that they should pay for (a portion of) the costs of pole 3, up to an amount not exceeding their private benefit.”*

115. In our opinion, the situation described in the first paragraph above represents an inefficient use of grid infrastructure. The investment in Pole 3 is sunk, and so when North Island load can be served more cheaply by South Island generators, it is efficient for that infrastructure to be used to facilitate that least-cost outcome. If South Island generators act in the manner envisaged in the above passage, prices in the wholesale market will be higher than would otherwise be the case. This is unambiguously harmful to consumers.

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<sup>57</sup> However, even in this scenario the efficiency of the final price to consumers may be compromised. This is because consumers will now see these interconnection costs in higher variable energy prices. If those costs were previously recovered through fixed charges, then this is likely to have been more efficient (given that the elasticity of demand for connection to the electricity grid is extremely low).

<sup>58</sup> EA Issues and Proposal Paper, paragraph 38.

116. In contrast, the perceived ‘benefit’ – identifying and charging only those parties that are ‘private beneficiaries’ – represents only a wealth transfer. Although South Island generators may benefit from avoiding the cost of Pole 3, it is simply recovered from other consumers, leaving no ‘net’ benefit.
117. In our view, it is not worthwhile to risk compromising the efficiency of the wholesale dispatch process in this manner in order simply to identify the private beneficiaries of a past (sunk) investment and to facilitate a series of ‘welfare neutral’ wealth transfers. It should be remembered that:
- the investment in Pole 3 was deemed to be efficient – it is for that very reason that it was built;
  - the SRMC of using Pole 3 is very low, i.e., it is limited to the costs associated with losses and constraints; and
  - the long-run marginal cost (LRMC)<sup>59</sup> of the next capacity expansion is also very low, because the value of any deferral of that future capacity increment is low due to the effect of discounting.<sup>60</sup>
118. All of these factors suggest that the TPM should *encourage* the use of Pole 3 – and of past investments more generally. However, the proposed methodology is likely to do the opposite and risks harming consumers. In our opinion, there is no sound economic basis for designing the TPM in a way that might cause generators to restructure their wholesale bids to avoid incurring sunk costs.<sup>61</sup>
119. Moreover, there is not necessarily any reason to think that generators will modify their bids in a way that causes them to collectively recover the exact amount of additional ‘beneficiaries-pay’ transmission charges. First, if different generators have different expectations about the precise quantum of additional charges they will face, they may under- or, more problematically, *over*-estimate those costs. In fact, when faced with this uncertainty, generators might err on the high side when forecasting the cost, all other things being equal.
120. This conduct would reduce the efficiency of the wholesale dispatch process. For example, if a generator over-estimates the additional \$/MWh charges it will face

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<sup>59</sup> LRMC reflects the cost of serving an incremental change in demand in a market, assuming all factors of production can be varied. Importantly, because LRMC is a long run concept, it accounts for the fact that firms have the option of *expanding their capacity* in order to meet an incremental increase in demand. Measuring LRMC involves estimating the costs involved with undertaking a capacity expansion *sooner than would otherwise be the case* in response to that change in demand.

<sup>60</sup> For example, the value today of deferring by one year a \$1b investment expected to be made in 12-months’ time is much greater than the value today of that same one year deferral applied to a \$1b investment to be made in 10 years’ time. It follows that the LRMC of the next capacity expansion increases the closer the time comes to when that increment is needed. *See*: NERA Report, p.14.

<sup>61</sup> It is possible that the proposal may even give rise to market power problems if it enhances generators’ ability to raise their rivals’ costs (either of their generating units or an affiliated retailer).

through this element of the TPM, factors that extra amount into its bid and then becomes a marginal generating unit, then:

- wholesale spot prices will be higher throughout the country (or within a particular region, if transmission constraints apply); and
- those prices will exceed the underlying SRMC of generating, i.e., operating and maintenance costs plus transmission charges.

121. Even where a generator underestimates its costs and bids lower than its actual costs this will tend to result in an economically inefficient dispatch (with that generator being dispatched when it was not truly the lowest cost).
122. Second, ‘marginalising’ what was previously either a fixed cost (HVDC), or a cost recovered from off-take customers (interconnection charges) will reduce the certainty of cash-flows for generators (and retailers). This additional risk, in effect, represents an additional ‘cost of doing business’ that generators will expect to recover through their prices. Specifically, if the proposal is implemented, one might expect to see generators (and, in turn, retailers) incorporating additional risk premiums in their prices over time. We describe this amplification of risk and its attendant effects in more detail in section 5.
123. These factors would result in short- to medium-term static inefficiencies and inappropriate investment signals that may compromise dynamic efficiencies over the longer-term. These distortions above may be exacerbated by the proposal to levy 50% of the ‘residual’ charge on generators based on their contribution to RCPI. This new charge has the potential to further compromise the efficiency of grid usage.

### 4.3 RCPI Charge

124. For the 2012/13 pricing year, the RCPD interconnection rate is \$90.66/kW, or around \$90,000/MW. In other words, over 100 half-hour peaks (in the LNI and LSI), every MW of peak demand attracts around \$900 in transmission costs, or \$1,800/MWh (\$900 x 2). Similarly, over 12 half-hour peaks (in the UNI and USI), every MW of demand attracts around \$7,500 in transmission costs, or \$15,000/MWh. Although off-take customers might try to switch or reduce load to avoid those peaks,<sup>62</sup> there is no direct effect on generators’ wholesale bids.
125. Under an RCPI arrangement, whenever a generator perceives there is a significant probability that a given trading period will be a chargeable peak it can be expected to factor this information into its offer price in the wholesale market. By doing so, it runs the risk of not being dispatched, which entails costs. However, depending upon how the charge is designed, the profits foregone from not generating during the

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<sup>62</sup> As we mentioned earlier, this is more feasibly achieved in the UNI and USI regions, because it is far more difficult to control 100 peaks.

period may be lower than the additional transmission costs it would face if a peak occurred and it had not factored the additional RCPI charge into its bid.

126. Currently, the \$90.66/kW interconnection rate<sup>63</sup> is used to recover 68% of total transmission costs through the RCPD charge.<sup>64</sup> The percentage that will need to be recovered via the RCPI charge will be lower, since it only needs to collect half of whatever interconnection costs remain after the ‘beneficiaries-pay’ charge is applied. The EA estimates that the RCPD and RCPI charges will recover between 5% and 50% of total transmission costs and so,<sup>65</sup> based on that analysis, the RCPI charge may need to recover between 4% and 37% of interconnection revenue.<sup>66</sup>
127. Suppose that the RCPI charge in the region of interest is levied based on generators’ contribution to 100 peaks (i.e., N=100). We noted above that, currently, every MW of peak demand attracts \$1,800/MWh in transmission costs. If the RCPI charge must deliver, say, 20.5% (the mid-point between 4% and 37%) of the existing interconnection revenue, every MW of additional peak injection would attract the equivalent of around \$370/MWh in transmission costs (\$1,800MWh x 0.205). Unlike the RCPD charge, this can be expected to affect spot market outcomes.
128. Specifically, when formulating their bids, generators will assess the probability that a period will be one of the 100 peaks. They will include in their estimate of SRMC (and presumably their bid prices) the probable cost to them of this charge. This will result in elevated prices in the wholesale market during periods of high demand. This is not necessarily an inefficient outcome in and of itself.
129. Higher peak prices can be appropriate if they reflect an estimate of the cost of using the grid in the peak period (in terms of heightened probable VoLL and/or heightened need for new capacity investment). It is not obvious that the RCPI approach will do this. For example, it is not necessarily the case that every one of those 100 peaks (or even any) will see demand approaching maximum capacity. In fact, there may be plenty of spare capacity, despite it being a peak. In those circumstances, the actual costs imposed by ‘peak’ injectors may be no different to the costs imposed by ‘non-peak’ injectors, yet the RCPI charge is levied nonetheless.
130. The RCPI will also increase uncertainty. To illustrate, imagine that the ‘true SRMC’ component of an offer price would otherwise be \$300/MWh. As we noted above,

<sup>63</sup> See: Transpower, *Year Specific Data for 1 April 2012*, available at: <https://www.transpower.co.nz>.

<sup>64</sup> In 2012/13, interconnection revenue is \$547m, and accounted for 68% of the \$805m total transmission revenue for the pricing year.

<sup>65</sup> EA Issues and Proposal Paper, Figure 6, p.73.

<sup>66</sup> The EA estimates that the residual charge will recover from 5% to 50% of total interconnection revenue. In other words, based on the 2012/13 numbers, the total ‘residual’ revenue will be between \$40.25m (5%) and \$402.50m (50%). The RCPI charge will need to contribute half that sum and so will be between \$20.13m (\$40.25m x 0.5) and \$201.25m (\$402.50m x 0.5). It follows that the RCPI charge will be between 4% (\$20.13m ÷ \$547m) and 37% (\$201.25m ÷ \$547m).

the application of the RCPI may add up to \$370/MWh to the wholesale price during periods in which a peak was considered possible (or approaching double that implied by the EA's range of estimates). Note that this increase would be in addition to any uplift already resulting from the application of the 'private-benefit' charge described above. Moreover, remember that this 'risk-premium' would be factored into generators' offer prices whenever there was a significant probability of a peak – not just the 100 periods of actual peaks.

131. It follows that, if the RCPI charge is applied to, say, 100 peak periods, then generators can be expected to factor the above risk premiums into their bids in a number of periods that is some multiple of that say, 200 or 300, with some probability. There is again not necessarily any reason to be confident that generators will modify their bids in a way that causes them to collectively recover the exact amount of additional 'RCPI' transmission charges. The logic is the same as for the 'beneficiaries pay' charge described above, namely:
  - if different generators have different expectations about the precise quantum of additional costs they will face through the RCPI charge, they may under- or, more problematically, *over*-estimate those costs when formulated bids; and
  - more generally, the introduction of an RCPI charge would reduce the certainty of generators' (and retailers') cash-flows and thus the 'cost of doing business' – they may therefore incorporate additional risk premiums in their prices.
132. Short of eliminating the RCPI charge entirely, the most effective way to reduce these incentives is to recover the charge over a greater number of peaks. The extreme approach would be to recover it over all of the 17,520 half-hour periods in a year. Doing so would swing the 'bid arithmetic' in such a way that the foregone profit in a period from not being dispatched would exceed the additional transmission costs incurred. However, at that point the charge essentially resembles a broad-based tax, which begs the question: why levy that tax on generators?
133. Levying a 'tax' on generators would appear not to offer any meaningful prospect of eliciting desirable behavioural change, since it does not produce a 'price signal', as such. Instead, at that point, the principal purpose of the RCPI charge would be to collect the residual sum of unrecovered revenue in the least distortionary way. In our opinion, that objective would be likely to be best achieved by continuing to recover the sum from the broader base of off-take customers. Moreover, levying an RCPI charge risks reducing the effectiveness of the RCPD charge.
134. As we mentioned above, we understand that the RCPD element of the current interconnection charging regime is generally thought to be working well. The proposed change would dilute the strength of the signals currently being sent to off-take customers in regions prone to constraints. This is because the RCPD charge will only need to recover between 4% and 37% of the revenue that it currently delivers (based on EA estimates). This effect could be mitigated by reducing the

number of peaks (i.e., by ‘recalibrating’ the signal) but, as we explained above, there would be no incremental benefit associated with the new RCPI element.

135. It may therefore be feasible to introduce an RCPI charge without making things *too much worse*. This is likely to involve spreading the RCPI charge over a large number of peaks and reducing the number of peaks for the RCPD charge. However, the relevant threshold for change is whether the charge will promote the efficient use of and investment in infrastructure. In our opinion, it would not. Irrespective of its design, an RCPI charge would seem not to offer any clear benefits and, if it was not implemented carefully, it could give rise to a number of distortions.

#### 4.4 Summary

136. Currently, the New Zealand wholesale market design means that, most of the time, generation plant should be ‘dispatched’ in an efficient ‘least cost’ basis, according to its economic merit order, as given by the ascending SRMC (as bid) of running each type of plant. The RCPD-based interconnection charge is also generally viewed as being a positive feature of the New Zealand arrangements. The proposed methodology risks compromising both of these beneficial aspects of the New Zealand market, without offering any obvious off-setting benefits.
137. The ‘beneficiaries pay’ charge risks causing generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments. This would distort the dispatch process and give rise to higher wholesale prices, in order to facilitate wealth transfers that offer no efficiency benefits. The charge will also make generators’ cash-flows less certain, which may result in additional risk premiums being incorporate in wholesale (and, in turn, retail) prices over time.
138. The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge. Although it may be possible to design the charge so as to mitigate these distortions, it would still not offer any clear benefits, which obviates the rationale for such a change.

## 5 Risk Amplification

139. The EA is currently exploring mechanisms to help wholesale market participants manage price risks caused by constraints on the national grid. It is also examining ways of facilitating, or providing for, an active market trading financial hedge contracts for electricity.<sup>67</sup> These two priority projects are explicitly directed at mitigating volatility and managing risk. These projects may be undermined if the proposal is implemented, since it has the potential to amplify risk throughout the entire supply chain, with myriad attendant consequences.

### 5.1 Effect on Generators

140. The proposed methodology contemplates generators paying interconnection charges. This would ‘marginalise’ a cost that previously was either fixed (the HVDC charge) or recovered from off-take customers (interconnection charges). Generators can be expected to take those additional variable costs into account when formulating their wholesale bids. In sections 4.2 and 4.3 we explained that this may precipitate a number of outcomes:

- The ‘beneficiaries pay’ charge may cause generators to adjust their bids so as to avoid bearing a greater share of the sunk costs of past investments. The consequence is that prices in the wholesale market will be higher in some parts of the country than if generators had not modified their conduct.
- Generators’ cash-flows will also be less certain, which 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, regardless of whether generators engage in the above conduct.
- The RCPI charge may create further distortions if it is not designed carefully. In particular, it may inflate further the additional risk premiums (described above) that generators may require to off-set reduced certainty of cash-flows. It may also weaken the beneficial incentives provided by the existing RCPD charge.
- Different generators may also have different expectations about the precise quantum of additional transmission costs they will face through the ‘beneficiaries pay’ and RCPI charges. They may therefore under- or, more problematically, *over*-estimate those costs when formulated bids.

141. In one way or another, these outcomes are all products of the additional volatility and uncertainty likely to be associated with the proposal. Put simply, it is conceivable that wholesale prices will be higher and significantly more volatile

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<sup>67</sup> See: <http://www.ea.govt.nz/our-work/programmes/priority-projects/>.

under the proposal than under the current TPM. This will, of course, have implications for retailers who will ultimately be forced to pay those prices.

## 5.2 Effect on Retailers

142. Electricity retailing is essentially a ‘risk management’ function that intermediates between the large scale transactions and risks arising in the spot market and the rather different needs of individual end users, who will generally have a lower appetite for risk.<sup>68</sup> Customers pay retailers for this risk management service (which is bundled with metering, billing services, and so on) and, in return, they are offered a price for delivered energy that is typically fixed for a year.
143. Before it can set its prices, a retailer must estimate the costs that it is likely to face throughout the period for which those tariffs will apply – usually a year. Anything that serves to increase the volatility of retailers’ input costs over that timeframe may cause those businesses to include additional premiums in their tariffs to reflect that heightened risk. In our opinion, the proposal is likely to have that effect on prices in the retail market, because:
- retailers are likely to face more volatile wholesale energy costs, for the reasons we set out in the previous section; and
  - further volatility will be introduced by the new SPD-based interconnection charge that retailers will be required to pay.
144. It is likely to be a challenging exercise for a retailer to predict the quantum of SPD-based charges that it will be required to pay over the course of a year. The pattern of ‘private benefits’ will depend on load-flow patterns (which may be affected by the conduct of generators, described above), and where and when new generation/load connects and disconnects. Changes in any of these factors could have a significant impact upon a retailer’s input costs, and its profitability.
145. There appears to be no way of hedging against those risks through financial instruments, since no counter-parties would exist that would be prepared to take the ‘other side of the bet’. The only way to deal with that increased cost of risk is through retail prices. Retailers will therefore face a choice:
- on the one hand, if they price ‘aggressively’, they may win more customers, but will face significant financial repercussions if their transmission costs turn out to be higher than expected; and

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<sup>68</sup> Although the volume of electricity that will be consumed by customers can be forecast, it cannot be known for certain. The same can be said for pool prices. To mitigate the risks they face from uncertain volumes and prices, retailers may enter into financial hedging contracts with generators or third parties. Larger retailers are also insulated to a material extent by the ‘natural hedges’ provided by their own generation portfolios.

- on the other hand, if they price ‘conservatively’, they will protect themselves against higher than expected transmission costs, but they may lose customers if other retailers adopt a riskier strategy and adopt lower prices.
146. On balance, in our view the second scenario is more likely. Specifically, the reduced certainty of cash-flows and increased input price volatility is likely to result in retailers incorporating additional risk premiums in their tariffs. Larger retailers may have an advantage over smaller retailers in this respect, since they will generally have a greater stock of institutional capital upon which to draw. They may therefore be better placed to predict the likely quantum of SPD charges and to arrive at an appropriate risk premium.<sup>69</sup>
147. Larger retailers may also be better placed to manage the increased volatility in wholesale energy costs described in the previous section. That is because they are more likely to be on ‘both sides’ of a transaction, i.e., by owning both generation and retailing assets.<sup>70</sup> Although a business’s retail arm may face a higher/more volatile wholesale price, its generation arm may be receiving that same high price (although not necessarily<sup>71</sup>). Because smaller retailers do not have these ‘natural hedges’, the amplified wholesale risk may be felt more acutely, i.e., it may:
- make them especially vulnerable to any wholesale price shocks brought about by the types of bidding conduct described above (and in more detail in sections 4.2 and 4.3), with the associated financial detriments; and
  - potentially increase their net spot market exposure and, in turn, the prudential security that they are required to provide under Part 14 of the *Electricity Industry Participation Code 2010*.<sup>72</sup>
148. The increased price volatility may therefore make it more difficult for smaller businesses to enter the retail market and to expand once there. This is potentially problematic because, although small retailers currently comprise only a modest share of the market,<sup>73</sup> they appear to have a significant disruptive influence on

<sup>69</sup> Larger businesses may also be best placed to undertake load control during predicted periods of peak demand (e.g., switching off interruptible load) so as to reduce the quantum of transmission charges that they are assigned during those times.

<sup>70</sup> These providers are sometimes called ‘gentailers’.

<sup>71</sup> If there is nodal price separation and a generating unit is distant from the retail load, then the business will not necessarily be on ‘both sides of the bet’ – its generating arm may not receive the high price being paid by its retail arm.

<sup>72</sup> Prudential security may take the form of a cash deposit, a bank guarantee, a third party guarantee from a party with an acceptable credit rating, a bond from a surety with an acceptable credit rating, and/or a hedge contract lodged with and settled by the clearing manager. Parties with an acceptable credit rating (A- Standard & Poors or equivalent) do not need to provide prudential security.

<sup>73</sup> Currently, the largest electricity retailers and their subsidiaries (Contact/Empower, Genesis/Energy Online, Mercury/Bosco Connect, Meridian/Powershop and Trustpower) account for around 95% of the New Zealand market. (These shares are based on the percentage of energised installation control points

prices and service offerings. In other words, the heightened risk precipitated by the proposal will not only increase retail prices, it may also serve to reduce competition at the retail level.

### 5.3 Summary

149. There is a strong likelihood that the proposal would significantly increase price volatility and amplify risk throughout the supply chain. This may cause generators and retailers to incorporate additional risk premiums in their prices. The retailers that are likely to be least well-placed to manage these additional risks are smaller retailers that do not have 'natural hedges'.

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(ICPs) held by each retailer as at November 2012. *See:* <http://www.ea.govt.nz/dmsdocument/14146>). The remainder of the market is made up of a number of small, independent retailers such as Tiny Mighty, Just Energy and King Country Energy (*See:* <http://www.switchme.co.nz/residential/power-companies.php>).

## Appendix A Some History

150. In this appendix we recount some history. We do so because most, if not all of the material presented in the EA paper has been considered many times before. Within the last two and a half years, three separate bodies have conducted wide-ranging reviews of the TPM – including the CEO Forum, the TPAG and the EA’s predecessor (the Electricity Commission). However, after careful (and lengthy) consideration, these groups recommended only incremental revisions to the TPM.
151. The EA appears to have reached a different conclusion based largely on its belief that the wider application of ‘market-based approaches’ and the ‘beneficiaries-pay’ principle will lead to better outcomes. That being the case, it is worth beginning our retrospective in the early 2000s. At that time, it was thought that applying these very principles would give rise to efficient, market-driven transmission pricing and investment. However, that is not what transpired.

### A.1 Market-based Transmission Investment

152. The initial thinking in New Zealand (and elsewhere) was that the existence of full nodal pricing would give rise to the possibility of market-driven transmission pricing and investment being undertaken by parties that would benefit from those investments, i.e. the beneficiaries. In principle, users (or groups of users) have an incentive to invest in new transmission capacity if the cost (to them) of augmentation is expected to be less than the continuing costs (to them) of the losses and constraints that will otherwise be incurred.<sup>74</sup>
153. The expectation was that investment by beneficiaries would reduce (or eliminate), the need to undertake centrally planned transmission investment, and to reduce (or eliminate) the need to fund such investment through regulated transmission prices. To this end, in 2002 the industry and the government canvassed the possibility of introducing financial transmission rights (FTRs) in order to create property rights that would improve the potential for market-led transmission investment.<sup>75</sup>
154. Of course, FTRs were not introduced at that time and, to date, there have been no user-driven transmission investments in HVAC or HVDC assets. In hindsight, that

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<sup>74</sup> Such investors need not receive a regulated revenue stream. Rather, the motivation for investment is to avoid the costs of future losses and congestion. However, to ensure that investors do not lose the benefits of their investment, they must receive a right to any network ‘congestion rents’, ie, revenue that arises from a divergence in the spot price between locations, should the link in which they have invested become congested in the future. Such rights might be ‘physical rights’ to the dedicated infrastructure, or rights that are purely financial in nature – FTRs.

<sup>75</sup> Such rights were intended also to allow market participants to hedge locational price risk resulting from transmission congestion. See: E Grant Read, *Financial Transmission Rights for New Zealand: Issues and Alternatives*, prepared for the New Zealand Ministry of Economic Development, 8 May 2002.

outcome is unsurprising, when one considers the formidable obstacles presented by the economic characteristics of transmission networks. These factors dramatically reduce the attractiveness of market-based investments, and do not obviate the need for some degree of centralised transmission planning and regulated pricing. These challenges include:<sup>76</sup>

- the economies of scale associated with new transmission investments, which mean that, once built, transmission lines eliminate congestion, rendering any physical or FTRs worthless;
- the strong incentive that parties have 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.

155. To be sure, market-based and beneficiaries-pay approaches have their place – even in a transmission pricing framework.<sup>77</sup> However, the characteristics of transmission and the practical challenges described above mean that there are limits to their usefulness, and seeking to apply those principles too widely can lead to inefficiency. So it proved in New Zealand. It is widely accepted that the experiment with market-based transmission investments and pricing during this period failed to deliver dynamically efficient outcomes and resulted in underinvestment.

156. By early 2000, broader concerns about the performance of the electricity sector resulted in a Ministerial Inquiry to examine whether the regulatory arrangements for the transmission, distribution, wholesale and retail sectors were best suited to ensuring that electricity was delivered in an efficient, reliable and environmentally sustainable manner to all consumers.<sup>78</sup> The government indicated that, if necessary, it would introduce legislation which would enable it to regulate.

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<sup>76</sup> In principle, from an economic perspective, the conditions for optimal expansion of the transmission network are that: 1) additional generation capacity should be built only if the total savings in the cost of generation (and demand management) exceed the additional transmission cost; and 2) additional capacity should be sized such that the marginal cost of generation savings and loss reductions (indicated by the difference in future spot prices – or generation costs – at different locations) equals the marginal cost of building additional capacity. In other words, in principle, investment will be efficient up to the point where the cost of one more unit of transmission capacity – the long-run marginal cost (LRMC) – is equal to the avoided cost of future constraints and losses – the short-run marginal cost (SRMC). However, the challenges listed above mean that it is neither feasible nor even advisable to seek to implement this decision rule in practice.

<sup>77</sup> Connection assets are an example.

<sup>78</sup> See: <http://www.ea.govt.nz/about-us/structure/background-to-governance-and-regulation/>.

157. In response, industry participants began developing a set of self-governance arrangements. In April 2003, the Transport Working Group (TWG) of the Electricity Governance Establishment Committee (EGEC) put forward an integrated proposal for the sector. We understand that part of the suggested arrangements was a proposal that new transmission investments be required to have support from 75% of the perceived beneficiaries.<sup>79</sup> This mechanism was intended to preserve some of the elements of a market-based approach for new transmission upgrades.<sup>80</sup>
158. However, later that year the arrangements put forward by the EGEC did not attract sufficient support from the industry, which led the government of the day to establish the Electricity Commission ('EC' – the EA's predecessor) under the *Electricity Act 1992*, with a view to regulating the market. Upon the inception of the EC in 2003, the *Electricity Governance Rules* (EGRs – developed by the Ministry of Economic Development) were introduced, including a regulatory TPM.<sup>81</sup> The arrangements resembled closely those that had been proposed by the EGEC, but with at least one notable exception.
159. Namely, the 'market-based arrangements' for undertaking new transmission investments that had been proposed by the EGEC (and rejected by the majority of the industry) were excluded and replaced by an administrative process. Those administrative mechanisms remain a feature of the TPM today – the current incarnation of which took effect on 1 April 2008. The EA stated in its decision-making and economic framework paper that it is 'unclear' why this administrative approach was favoured, but offers two possible explanations:<sup>82</sup>
- concern that the market-based approach would have resulted in under-investment due to problems with free-riders (the EA claims that the proposal contained procedures designed to overcome these problems); and
  - a view that the associated decision-making process would be too time-consuming and costly (the EA states that these costs must be weighed against the time spent debating transmission investments under the TPM).
160. A potential additional explanation is that the architects of the EGRs were cognisant of the myriad challenges associated with giving effect to a beneficiaries-pay

<sup>79</sup> See: EA Consultation Paper, paragraphs 4.3.13 to 4.3.17.

<sup>80</sup> The idea was that, over time, as more and more grid assets were upgraded, long-term contracts would have replaced the TPM as the means by which Transpower's revenue was generated.

<sup>81</sup> Note that there has been a transmission pricing methodology in existence in New Zealand since the 1980s, but it was not incorporated in regulations until 2003, whereupon it was included in the *Electricity Governance Rules* (it has since been incorporated into the industry Code). Note that Contact Energy Ltd (Contact) and Meridian Energy Ltd (Meridian) sought a judicial review of the process followed when the initial TPM guidelines were developed. This action was successful and the guidelines were set aside on 29 August 2005. See: *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J).

<sup>82</sup> EA Consultation Paper, paragraph 4.3.16.

principle in a transmission context, which we set out in sections 3.2 and 3.3. If so, the TPM – and this element in particular – might reasonably be characterised as a conscious policy response to an approach that was influenced too heavily by the desire to apply market-based approaches and beneficiaries-pay principles.

161. To be clear, we are postulating this alternative explanation with the benefit of hindsight. We do not know exactly why the administrative mechanism was favoured over the TWG proposal. Nonetheless, the exclusion of this particular element of the EGEN framework is conspicuous and indicates that there was widespread dissatisfaction with it at the time. Tellingly, the principles that underpinned that methodology have many parallels to those that have been applied in one form or another to arrive at the approach set out in the Issues and Proposal paper.

## A.2 Reviews of the TPM

162. The TPM defines how Transpower will recover the cost of its existing assets,<sup>83</sup> and is supplemented by administrative processes for approving new investments.<sup>84</sup> Since its inception, it has been the subject of significant ongoing controversy. This is more or less inevitable given that small changes in the methodology can lead to large changes in the incidence of charges. In just the last three years, the TPM has been the subject of three separate reviews – by the industry CEO Forum, the EC and the TPAG (a body that was formed as part of the EC review).
163. Each group undertook a thorough examination of the existing arrangements. The CEO Forum gave particular attention to whether the TPM could be modified so as to provide enhanced locational signals to grid users – especially generators (who do not currently pay interconnection charges).<sup>85</sup> The idea was to test whether a price signal could be introduced that would reduce the amount that Transpower would need to spend building and maintaining the grid, without imposing even higher costs elsewhere, e.g., higher fuel costs.<sup>86</sup>

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<sup>83</sup> It is therefore arguably more akin to a *cost* allocation methodology than a pricing methodology.

<sup>84</sup> These new investment approval prices used to be administered by the EA (then the Electricity Commission) under the auspices of the Grid Investment Test (GIT) framework. Those capital investment approval processes have since been transferred to the Commerce Commission under the new regulatory arrangements set out in Part 4 of the *Commerce Act 1986*.

<sup>85</sup> Generators are much more likely to respond to price signals than major load because it is a more important cost driver. Typically, the cost of transmission is a secondary consideration for major load when deciding upon a location. Other factors such as the cost of real estate, labour and the location of a key input into production (forests for a pulp and paper mill; and deep water port for an aluminium smelter, etc) will typically be more important.

<sup>86</sup> The most obvious additional cost would be the higher fuel costs that generators might be forced to pay by locating closer to load. If the increase in fuel costs is greater than the reduction in transmission spend, then society as a whole is worse off as a result.

164. The potential ‘signal delivery mechanisms’ that were considered included a ‘tilted-postage stamp’ methodology, and the ‘capacity-rights’ and ‘arbitrageur’ market models for the HVDC link. The touchstone for the assessment of each of those options was their potential to enhance economic efficiency by altering the commercial incentives facing market participants and ultimately their conduct, so as to produce more desirable outcomes. Change for the sake of change was not an objective. In particular, it was recognised that:<sup>87</sup>

*“[O]ptions that simply alter the incidence of transmission changes (which is inevitable) to the financial advantage of one party or another, but do not give rise to any material improvement, will simply impose needless additional regulatory costs. Ultimately, reform will only deliver economic benefits if desirable behavioural change is brought about. A reform option must lead to real changes in the commercial behaviour/decisions of the relevant parties, in the manner intended.”*

165. This criterion is critical – not just because it represents an uncontroversial threshold for change, but also because it was the lack of potential for desirable behavioural change that caused TPAG to recommend against the introduction of enhanced locational signals.<sup>88</sup> The modelling that was undertaken as part of that process (much of it by Transpower) revealed that there was little point in seeking to provide a locational signal, because:

- generation and load was likely to be built in largely the same locations, since location decisions were driven more by other factors (e.g., fuel availability) than by transmission prices; and
- Transpower had recently committed to several large investments (a 400kV capable link in the upper North Island, and Pole 3 of the HVDC), and so those costs could no longer be avoided, reducing the potential benefits of modifying the price signal.

166. The TPAG consequently concluded that there would not be sufficient cost savings from deferring transmission investments by introducing an enhanced locational signal (in large part because many of Transpower’s ‘big’ investments had already been decided upon). It therefore refocused its efforts on ensuring that the TPM did not create perverse incentives to use the existing sunk assets inefficiently. The three aspects of the TPM that it considered included:

- various arrangements for static reactive compensation, with the group favouring an amended kvar charge option;

<sup>87</sup> NERA Economic Consulting, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.1 (hereafter: ‘NERA Report’).

<sup>88</sup> See: Transmission Pricing Advisory Group, *Transmission pricing analysis, Report to the Electricity Authority*, 31 August 2011 (hereafter: ‘TPAG Final Paper’) and Transmission Pricing Advisory Group, *Transmission pricing discussion paper*, 7 June 2011 (hereafter: ‘TPAG Discussion Paper’).

- whether shallower or deeper connection charges should be employed, with the group concluding that there was not a clearly attainable efficiency gain to warrant a change from the status quo; and
- the allocation of HVDC costs – a matter that divided the group, with some members favouring a transition to a postage stamp charge and others considering that the potential efficiency gains were not sufficiently material to warrant such a change.

167. In broad terms, the CEO Forum and the TPAG that followed it concluded that the current TPM was, for the most part, sound – and not demonstrably inferior to alternatives. Those bodies also recognised that material changes would entail substantial wealth transfers and risk giving rise to unintended consequences. That prudence is as advisable now as it was then. Many of these potential downsides arguably do not receive sufficient attention in the Issues and Proposal paper, as we have explained in the body of this report.

### A.3 Summary

168. We have navigated this period of history because it is worth remembering that, in the early 2000s, it was thought that applying many the principles that underpin the proposed methodology would give rise to efficient, market-driven transmission pricing and investment. It did not. Instead, that experiment failed because insufficient attention had been given to the impracticability of applying market-based principles and the ‘beneficiaries pay’ philosophy to certain types of transmission infrastructure, given its economic characteristics.
169. The result was market failure, which manifested primarily in underinvestment and led, ultimately, to the introduction of the TPM and the associated administrative processes for approving new investments. Since its inception, the TPM has, understandably, proved controversial – particularly the charging arrangements for the HVDC link. However, although several recent reviews have identified some areas for incremental improvement, there was no call for fundamental changes, or for the wider application of ‘beneficiaries pay in proportion to benefit’ principles.

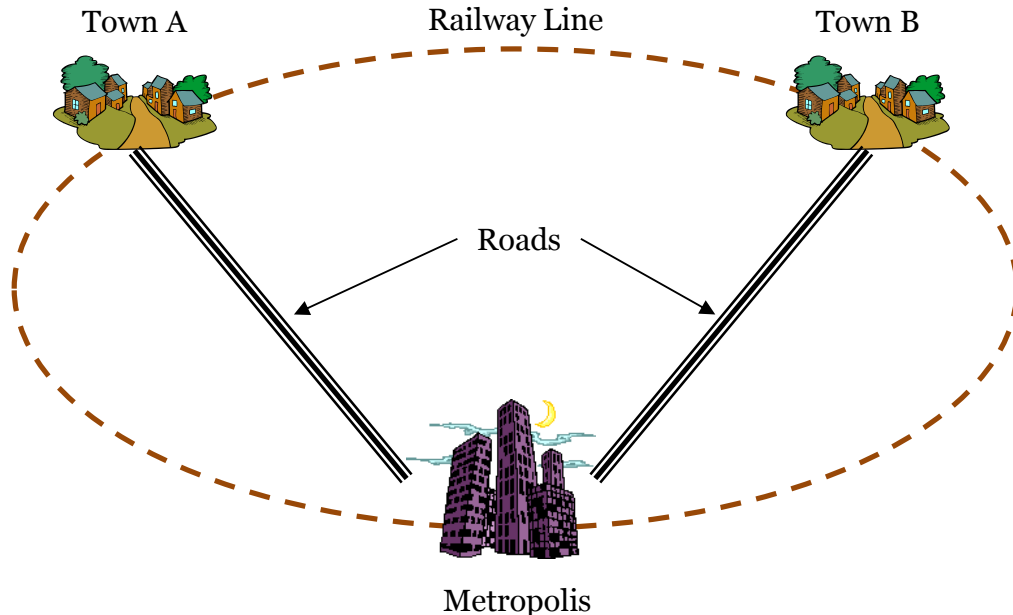
## Appendix B Worked Example

170. In this appendix we provide a worked example from outside the transmission sector that illustrate the potential shortcomings associated with setting prices for a service based on the changing profile of beneficiaries. The example highlights the potential for such an approach to lead to ongoing disputes and, ultimately, inefficient investment outcomes.

### B.1 Road versus Rail

171. Imagine two country towns that have congestion problems on the existing highways connecting them to a local metropolis. Suppose further that the respective local councils have responsibility for the provision of the highways and the congestion problems could be solved by upgrading them. However, imagine that the congestion could also be alleviated by investing in a new shared railway serving both towns. Figure 2 illustrates.

**Figure 2 Investment in Road versus Rail**



172. Suppose finally, for the sake of simplicity, that the costs and benefits offered to each town by the two options (upgrading the highways or building the train line) are identical (other things being equal). The following matrix describes the benefits and costs of each investment.

**Table 1 Matrix of Benefits**

<b>Option</b>	<b>Economic (social) Benefit per Town</b>	<b>Overall (social) Net Economic Benefit</b>
Train Only	$B_T$	Positive & the highest
Highway Upgrade Only	$B_H$	Positive & 2 <sup>nd</sup> highest
Train given Highway Upgrade	$B_{T/H} < B_T$	Negative
Highway Upgrade given Train	$B_{H/T} < B_H$	Negative

173. Table 1 illustrates that that overall benefits are maximised if the ‘train only’ investment is made. It also illustrates that, if the train line is built, there is no benefit associated with upgrading the highway – in fact, the outcome is negative. In other words, the most efficient outcome is that in which the railway investment proceeds and the highway upgrade does not.
174. Imagine that a central planner is cognisant of the above values and determines that the railway line should be built. Imagine also that she simultaneously commits to charge the citizens of each town a price for using the railway line that reflects their proportion of ‘private benefits’ – a sum that will change over time as circumstances evolve in each location (in the same way that the EA proposes to change interconnection charges over time). We explore the implications below.

## B.2 Implications

175. If neither town upgraded their highway, then the railway costs will be shared equally, because each benefits by the same amount “ $B_T$ ”, i.e., their shares will be 50% ( $B_T \div (2 \times B_T)$ ) of the cost of the railway line. However, if one town decides subsequently to upgrade its highway, then the benefit that it derives from the railway will fall to  $B_{T/H}$  – reflecting the lower valuation its citizens would then place on train travel, given the improvement to the road. The town’s share of benefits from the railway line will consequently decline and its citizens will have to pay a smaller proportion of the total costs, i.e.,  $B_{T/H} \div (B_{T/H} + B_T) < 50\%$ .
176. Each town’s decision about whether to upgrade its highway therefore ceases to be about the costs and benefits associated with that bespoke investment. The additional factor that is now relevant to that investment calculus is the expected change in the costs they will be required to pay for the railway line – a sunk cost. In effect, each town now receives an artificial subsidy for upgrading its highway in the form of a lower allocation of the costs of the railway. Mathematically, the subsidy can be expressed as follows:

$$\text{Artificial subsidy for highway} = \text{total railway line costs} \times (50\% - B_{T/H} \div (B_{T/H} + B_T))$$

177. This artificial subsidy may be sufficient to ‘tip’ the ‘private’ value of the highway upgrade (given the existence of the railway line) from negative to positive – causing an inefficient investment to be undertaken. Alternatively, if the town did not have responsibility for the highway upgrade, it would have a strong incentive to lobby the central planner to undertake this inefficient investment. It would do so not because of the benefits of the highway per se, but because of the costs that it would then avoid by contributing less to the past investment in the railway.
178. By way of example, imagine that the total cost of the railway train per annum was \$100m and that the cost of a highway upgrade was \$20m. Suppose also that the benefits of a highway upgrade given that the railway line already exists are equal to \$15m. In these circumstances, it is inefficient for the highway upgrade to proceed, because it has negative net benefits:

Net benefits of highway given the existence of the railway line = \$15m - \$20m = **-\$5m**

179. However, imagine that upgrading the highway reduced the ‘private benefit’ to the town from having the railway line by 20% (because its citizens use it less, following the improvement in the highway). In this case, that town’s share of the railway’s costs will fall from 50% to 44%  $((1 - 0.2) \div (1 + 1 - 0.2))$ . This will reduce its share of the payments for the \$100 pa railway costs from \$50m pa to \$44m pa – a saving of \$6m pa. This will, in turn, make the investment in the highway privately profitable – but only because its allocation of the past investment cost is reduced.

### B.3 Summary

180. The above is a stylised example of the type of effects that one might expect to observe if the proposal is implemented. However, they may be even more pronounced due to the interconnected nature of the grid and the fact that all investments are undertaken by Transpower. In the above example, each town had to pay for their own highway upgrade and the benefits of this were localised to that particular town. In a transmission context, one might expect to see parties lobbying for a new investment for which they were not beneficiaries at all, simply because the interconnected nature of the grid means that they will be deemed greater or lesser beneficiaries of other assets.