COMPETITION ECONOMISTS GROUP

Economic Review of EA CBA Working Paper

A REPORT FOR TRANSPOWER

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Project Team:

Hayden Green

Dr Tom Hird

CEG Asia Pacific
234 George Street
Sydney NSW 2000
Australia
T: +61 2 9881 5754
www.ceg-ap.com

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1 Introduction

1. This report has been prepared by CEG on behalf of Transpower. It provides our views on certain aspects of the Electricity Authority's (EA's) Transmission pricing methodology cost benefit analysis (CBA) working paper.[1] That paper sets out the EA's proposed methodology for analysing the costs and benefits of different transmission pricing options. The EA intends to apply this framework when assessing the merits of different reform options in its second issues paper, which is scheduled to be released next year.

2. Transpower has asked for our opinion on the EA's suggestion that changes to the transmission pricing methodology (TPM) could give rise to short-term static efficiency benefits.[2] However, we also provide our perspectives on whether changes to the TPM might deliver long-term dynamic efficiency benefits, and how that might be captured within a CBA framework. We provide an overview of our principal conclusions in relation to these points below, and elaborate in more detail in the body of this report.

1.1 Static efficiency

3. There are significant problems with the proposition that changes to the TPM can deliver short-term static efficiency benefits. When one considers the economics of efficient transmission pricing it is apparent that the existing pricing arrangements are likely to result in highly efficient use of existing grid infrastructure. In industries characterised by large fixed costs such as electricity transmission, short term static efficiency is usually maximised by way of a "two-part tariff"; specifically:

   - a "unit price" for usage of the transmission grid that signals to users the short run marginal cost (SRMC) of transmission; and
   - additional charges that recover fixed (non-marginal) costs in the least distortionary manner, which often involves levying fixed charges.

4. The SRMC of transmission is equal to the physical energy losses incurred during transmission and the "opportunity cost" of any constraints. The full nodal pricing arrangements in the wholesale market mean that this SRMC of transmission is reflected in the difference in spot prices across nodes throughout the country. In other words, the "unit price" for grid usage recovered through the wholesale market reflects the SRMC of transmission, consistent with the first bullet above.

[1] Electricity Authority, *Transmission pricing methodology: CBA, Working paper,* 3 September 2013 (hereafter: "CBA working paper").

[2] CBA working paper, §6.14.

5. The various other "fixed" charges under the TPM through which Transpower recovers the remainder of its revenue requirement also appear to do a reasonably good job of minimising distortions to short-term production and consumption decisions.[3] The use of the existing grid is therefore likely to be very efficient under the current arrangements. It follows that there are unlikely to be any significant static efficiency benefits to be obtained through changing the way that transmission charges are levied for existing assets.

6. However, the potential for static inefficiency costs is clear – particularly if a variant of the "beneficiaries-pay" charge proposed by the EA in its first issues paper is implemented. These costs were canvassed extensively in our first report,[4] and stem from reduced wholesale dispatch efficiency, amplified risk throughout the supply chain and, potentially, reduced retail competition. The EA's CBA framework should therefore be modified to reflect the very limited scope for static efficiency gains, and the very real prospect of static efficiency costs.

1.2 Dynamic efficiency

7. The more likely source of *in principle* benefits from transmission pricing reform lies through the promotion of more efficient investment in new assets in the long term, i.e., through the enhancement of dynamic efficiency. We say *in principle*, because there are several factors that suggest that significant dynamic efficiency benefits are unlikely to be achievable *in practice*. Before a CBA framework could reasonably conclude that a change to the TPM will yield such benefits, it must also take into account a number of matters.

8. First, as the EA recognises, it is important for the CBA framework to establish a causal relationship between a change to the "status quo" and the attainment of a benefit.[5] To establish that link, it is first necessary to show that changing the TPM can produce a *material change* to investment outcomes. Those changes might involve Transpower (or generators or load) investing in different asset, or in a different location, or at a different time.

9. If changing the TPM has no discernible effect on future investment outcomes, then there can be no dynamic efficiency benefits recognised in a CBA. In other words, changes to the TPM that simply alter the incidence of transmission charges to the financial advantage of one party or another, but do not produce any changes to

3 The limited exception is the HAMI-based charge levied in relation to HVDC assets, which does lead to South Island generators withholding capacity in some circumstances. However, the other interconnection and connection charging arrangements do not appear to have a significant effect on market participants' consumption and production decisions, including generators' wholesale bids.

4 *See:* CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, pp.33-38.

5 CBA working paper, §8.1.

investment outcomes, do not produce dynamic efficiency benefits. The same outcome is achieved "with and without" the change.

10. To illustrate, suppose for the sake of argument that there was an unambiguously "perfect" TPM. Intuitively, one might expect that it would be beneficial to move to such a model. However, a CBA framework cannot *assume* that is the case – it must test it *empirically*. If it turns out that all market participants were likely to invest in exactly the same way, regardless of whether the hypothetical "perfect TPM" was employed, then it would not offer dynamic efficiency benefits relative to the status quo. However, there would be administrative costs associated with the change.

11. In other words, in order for changes to the TPM to deliver dynamic efficiency benefits, transmission prices must be capable of altering investment decisions in a material way. Before changes to the TPM can influence future transmission investment outcomes, they must first affect the investment decisions of generators and load. However, in practice, there are several other factors that are likely to be of much greater significance to the investment decisions of generators and load than transmission prices, for example:[6]

   - generators will tend to locate their plants based primarily on the availability of certain fuels (coal, gas, water, wind) – this may be more important than any feasible differentiation in transmission prices;[7] and
   - the investment decisions of large industrial load will be influenced by many considerations that are likely to be more important to them than transmission charges, including access to market, the proximity of customers, etc.

12. If these other factors outweigh any feasible differences in transmission charges across geographic locations and/or time, then grid users will continue to invest in the same way, and the profile of future transmission investments needed to meet their demand will be unaffected. For these reasons, it may be difficult to establish the requisite relationship between changes in the TPM and the investment decisions of generators, load and, ultimately, Transpower. However, establishing such a link is necessary part of any coherent CBA framework.

13. Second, even if it could reasonably be established that changing the TPM has the potential to affect investment outcomes – the effect must also be shown to be *beneficial*. If a dynamic efficiency improvement can be made, then it follows that there is a certain level of dynamic inefficiency associated with the existing investment and pricing framework. Indeed, the only way that a dynamic efficiency benefit can be obtained is through avoiding a dynamic inefficiency *cost*.

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6 For a more comprehensive discussion of these matters, *see:* Green., H, et al (2009), *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.12.

7 Investment decisions can also be influenced by pragmatic considerations such as the need to obtain the appropriate consents under the *Resource Management Act 1991*.

14. It has not been suggested (at least not explicitly) that the Commerce Commission's (Commission's) capital investment framework 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", or that the existing investment framework will lead to it doing so in the future.[8] It is consequently unclear where dynamic efficiency benefits would flow from in the event that investment outcomes could feasibly be altered (which is also unclear).

15. It is also relevant that Transpower will soon complete a $2 billion investment programme. Its capital investment will therefore be much reduced in coming years. This means that even if transmission pricing could "defer" future investments, the potential benefits from doing so may be small, given the point in the investment cycle. For example, the costs saved by deferring by 5 years an investment that would otherwise be made in 50 years will be much lower in present value terms than deferring an investment that would otherwise be needed tomorrow.

16. Third, even if the existing investment and pricing arrangements have the potential to result in material levels of dynamic inefficiency (which has not been established), that problem can only be addressed with the right price signal. For example, it may be possible to improve dynamic efficiency by providing a better signal to parties of the *long-run costs* of their actions on future transmission requirements. However, modifying the TPM to reflect the EA's "beneficiaries-pay" approach would not achieve this.

17. The approach instead seeks to estimate how much parties would be prepared to pay to avoid a particular asset being taken away. Such thought experiments have no role in the efficient pricing of capital intensive services. There is no reason to think that the amount that a party is perceived to benefit from an asset today bears any resemblance to the effect that parties' actions has on the long run cost of investing in that part of the grid in the future.[9]

18. For these reasons, we remain of the opinion that if the EA's preferred pricing reform remains a "beneficiaries-pay" approach applied to both new and existing assets a quantitative CBA is not needed to see why the proposal is unlikely to promote dynamic efficiency. However, if the EA perseveres with a quantitative assessment, its CBA framework must properly account for the above factors, as well as the fact that material static efficiency enhancements are unlikely to be achievable.

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8 For example, the EA does not seem to question directly the efficiency of the $2 billion in investments that was approved recently.

9 This is especially the case given that the recent $2 billion expansion will have created significant spare capacity. The SRMC of congestion and the cost (in present value terms) of future expansions are likely to be low at present, but this would not necessarily be reflected in "beneficiaries-pay" charges.

1.3 Structure of this report

19. The remainder of this report is structured as follows:

- **section two** describes the overarching objectives of transmission pricing and the concept of marginal cost, which is of central relevance to the achievement of static and dynamic efficiency;
- **section three** considers the extent to which the existing market arrangements reflect the efficient pricing principles described in section two and where the potential "gains" from TPM reform might consequently lie;
- **section four** considers the extent to which these potential sources of benefits (and costs) from transmission pricing reform are reflected in the EA's proposed CBA framework; and
- **section five** concludes.

20. In several places, this report draws upon material contained in our two earlier reports: CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013; and CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013.

2 Economic Efficiency and Pricing

21. In this section, we describe the overarching objectives of transmission pricing and the concept of marginal cost, which is of central relevance to the efficiency of pricing. This then serves as a reference point for our assessment of sources of potential improvement, which we undertake in the following section.

2.1 The objective of transmission pricing

22. The objective of any transmission pricing arrangements should be to encourage the efficient use of and investment in transmission. This should, in turn, promote competition between generation plant and more effective rivalry between retailers. There are two broad categories of efficiencies that can deliver economic benefits – static efficiency and dynamic efficiency. The former refers to the extent to which existing infrastructure is being efficiently utilised, and comprises:

- productive efficiency, which occurs when products and services are provided at the lowest possible cost, given the existing technology, i.e., if a firm manages to reduce the costs that it incurs to supply a product, then then this will enhance productive efficiency; and
- allocative efficiency, which occurs when firms are producing the right goods at the right price, i.e., if a firm drops its price and some customers who were previously unwilling to buy the product start to do so, while still enabling the firm to cover its costs,[10] then allocative efficiency has been enhanced.

23. Dynamic efficiency refers to the extent to which the right investments are made in the long term. For example, if the demand for a product supplied using certain infrastructure is growing over time then this may lead to frequent congestion and/or compromised service quality. Eventually, the short term cost of managing the consequences of that demand growth may be greater than the cost of investing in new capacity, at which point the dynamically efficient outcome is to invest in new infrastructure.

24. A key tool for achieving static and dynamic efficiency is the signals provided by the TPM. Because generators and consumers react to market signals, the level and structure of transmission charges has a potentially significant effect on network usage over the short term and, to a lesser extent, on long term transmission investment.[11] Economic theory provides clear guidance as to the price levels and

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10 Including an appropriate risk adjusted return on its capital.

11 Transmission charges may also affect the locational choices of new generation and energy intensive users, as well as potentially influencing the bidding conduct of generators.

structures that are most likely to promote static and dynamic efficiency in the presence of significant fixed costs.

25. It is worth briefly considering the distinctions between "fixed costs" and "sunk costs" in this regard. In its sunk costs working paper, the EA contends that these are more than "mere terminological quibbles".[12] It describes the former as "costs that do not alter with changes in production".[13] Sunk costs are then characterised as those parts of a firm's costs that cannot be recovered if it ceases operations, even in the long run, i.e., they are committed irrevocably.[14]

26. Under the EA's definition, even if a firm's assets could not be economically sold on second-hand markets or redeployed to other uses they would not be "sunk", provided that at least a portion of the costs could be recovered by selling the firm itself. On one view, this might be said to better represent a definition of "stranded costs". In any event, the precise technical definition of costs is of secondary importance to their *practical effect* on firm's production decisions.

27. The essential point we made in our previous report[15] is that in capital intensive industries, if one sets aside the prospect of selling the firm itself, many of its costs will be unavoidable. If assets are large, expensive and highly specific, it will rarely (if ever) be economical for a firm to try and sell them second-hand, or to deploy them to alternative uses. It was for this reason we characterised those costs as being "sunk for all practical purposes".[16] We return to this point in section 3.1.

2.2 SRMC and static efficiency

28. Static efficiency is maximised when the unit price for an additional unit of a product is equal to the SRMC of supplying it.[17] In the short run capacity is fixed, and so SRMC is the additional cost that a firm incurs by increasing its output by one unit, holding capacity constant.[18] When that unit can be supplied using existing capacity, SRMC will equal the operating and maintenance costs of producing it. However, when the existing capacity is at its limit, SRMC rises to whatever level is necessary to curtail the demand for that unit:

12 Sunk costs working paper, §5.2.

13 Sunk costs working paper, §5.23.

14 *Ibid.*

15 CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013, pp.4-5.

16 *Ibid.*

17 Professor Alfred Kahn described this as the "central policy prescription" of microeconomics. *See:* Kahn, A, (1988), *The Economics of Regulation, Principles and Institutions, Volume 1* (MIT Press), p.65.

18 In the short run, it is not possible to meet additional demand by investing in new infrastructure.

- if the existing supply is exhausted, demand by an additional customer cannot be met using the existing capacity – supply can increase no further; and so
- the unit price must increase to the point at which the additional customer no longer wants to buy the unit, i.e., the price must increase to reduce demand.

29. However, SRMC-based unit prices may not enable firms to recover all of their costs. For example, in capital-intensive industries, firms need to make a return on their existing assets. When existing capacity is plentiful, the SRMC of providing an additional unit of capacity may be very low, and SRMC-based prices may make no contribution to fixed costs. "Ramsey-Boiteux" pricing principles suggest that the most efficient way to address this situation is through a two-part tariff, whereby:[19]

- the price for an additional unit of the service in question is set equal to the SRMC of supplying it, for the reasons set out above; and
- fixed costs are then recovered in a way that minimises distortions to demand, e.g., through fixed costs based on respective customers' willingness to pay.

30. In other words, a key challenge is to levy additional charges on customers in a way that enables the costs of existing assets to be recovered, without compromising the static efficiency benefits obtained from the unit prices. Provided that can be achieved, this two-part tariff structure will maximise short term static efficiency in markets characterised by significant fixed infrastructure costs, because:

- the product will be supplied at the lowest possible cost, given the existing capacity and technology, promoting productive efficiency; and
- there is no inefficiently unserved demand, maximising allocative efficiency, i.e., demand is as high as it can be while still allowing firms to cover their costs.

31. Put another way, prices structured in this way will make the most efficient use of the existing assets during the period in which capacity is fixed. However, in the long run, demand no longer needs to be met from current capacity alone. Firms also have the option of expanding capacity to meet additional demand. There is a strong "in principle" link between SRMC, LRMC and the dynamic efficiency of capacity expansion decisions.

2.3 SRMC, LRMC and expansion decisions

32. When demand is growing over time, in the first instance it is often best to meet this using the existing infrastructure. For example, in the short run, the number of hotel rooms in Wellington is fixed. Initially, the most efficient way to deal with excess demand during peak periods (e.g., during the Wellington Sevens) will be through increasing the price of existing rooms to curtail demand. However, if the demand

19 *See:* Frank. P. Ramsey, "A Contribution to the Theory of Taxation", *Economic Journal* (1927), pp.47-61.

grows to the point where prices are *constantly* increasing to curtail demand (i.e., repeatedly throughout the year) then it may be more efficient to build more rooms.

33. In other words, eventually, a "tipping point" will occur at which the expected cost of *curtailing* demand increases beyond the cost of expanding capacity to *meet* that demand. At that point, it is efficient for new investment to take place. The "optimal investment rule" is for investment to occur when the long run marginal cost (LRMC) of expanding capacity to meet additional demand is less than the projected SRMC of curtailing it to levels that can be met with the existing capacity.

34. LRMC can therefore be thought of as the cost of serving a permanent, incremental increase in demand by augmenting capacity. Of course, in most industries, it is not practicable to add capacity in very small increments. For example, it is unlikely to be cost effective for a hotel to add new capacity "room by room" to meet an increase in demand. It will usually be more cost efficient to add capacity in large increments – e.g., several storeys at a time or by way of a new building – even if that new capacity is not fully utilised in right away.

35. In other words, there tend to be "economies of scale" associated with augmentations. Because capacity must be added in lumpy units, this gives rise to time-dependent fluctuations in LRMC *and* SRMC. In the period immediately following a "lumpy" investment there is likely to be ample spare capacity and the next expansion is likely to be some way off. In these circumstances, the expected SRMC of constraints and the LRMC of the next capacity expansion will both be relatively low. This is because:

- there should be enough capacity to meet demand most (perhaps all) of the time, i.e., there should be few instances in which demand needs to be curtailed; and
- the future cost (in net present value terms) of the next capacity expansion is low because of to the effect of discounting.[20]

36. During these periods, the efficient SRMC-based unit prices for that infrastructure are likely to be relatively low, so as to maximise the usage of that existing capacity. However, as demand grows over time and the next capacity expansion approaches, the SRMC of curtailing demand and the LRMC of the next expansion start to increase, because:

- existing capacity may be frequently insufficient to meet demand, i.e., SRMC-based unit prices may need to increase frequently to curtail demand; and
- the future cost (in net present value terms) of the imminent capacity expansion is likely to be very high because of the effect of discounting.

[20] For example, the cost (in present value terms) of undertaking a $100m expansion tomorrow is much higher than the cost of undertaking a $100m expansion in twenty years' time.

37. During these periods, the efficient SRMC-based unit prices for that infrastructure are likely to be relatively high, to ration demand and signal that there are profitable opportunities for new investment. In competitive markets, the forces of demand and supply can be relied upon to provide incentives to firms to structure their prices efficiently, promoting static efficiency. Motivated by the prospect of earning profits, firms can also be expected to act on the investment rule described above, promoting dynamic efficiency in the long run.

3 Application to Transmission

38. In the following section we consider the extent to which the existing market arrangements reflect the efficient pricing principles described above and where potential "gains" might consequently be made through reform to the TPM. We then compare this with the sources of potential benefit identified by the EA in its working paper. We begin by considering the extent to which the existing pricing promotes short term static efficiency, before considering long term dynamic efficiency.

3.1 Short term static efficiency

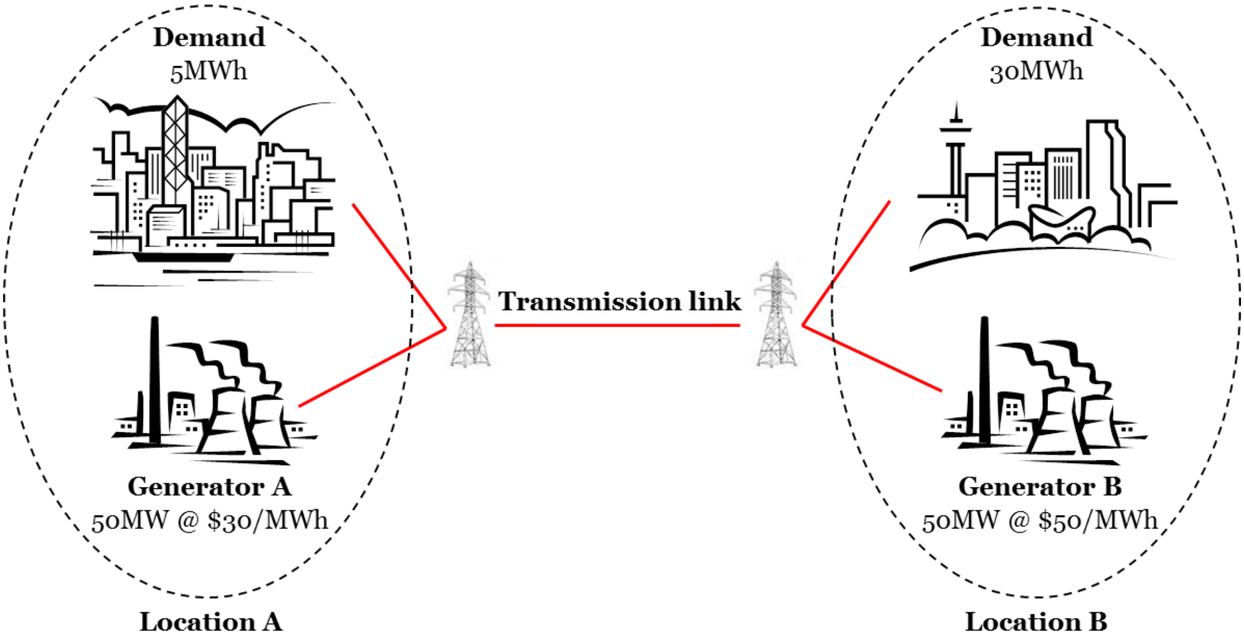
39. In the context of the transmission network, in the short term, demand must be met using the existing assets. The SRMC of serving an incremental increase in demand therefore depends upon whether the grid is constrained. When the grid is uncongested, an incremental increase in demand can be met by the cheapest available source of generation. In this instance, the SRMC of transmission is equal to any physical energy losses incurred during transmission. This changes when constraints emerge.

40. When a part of the transmission network becomes congested it is no longer possible to meet an incremental increase in demand in that location with increased supply from the cheapest available generation. Additional supply must instead be sourced from more expensive generators producing in other locations unencumbered by constraints. In this scenario, the SRMC of transmission is equal to physical energy losses *plus* the opportunity cost of congestion, i.e., the cost of deploying more expensive generation.

41. In New Zealand, the full nodal pricing arrangements in the wholesale market mean that the difference in spot prices between nodes should reflect this SRMC of transmission, irrespective of whether constraints exist. For example, in Figure 1 below, if the transmission link is unconstrained and the cost of energy losses is $10/MWh, then generator A will be dispatched to serve both locations. However, the spot price in location B will be $10/MWh higher, reflecting the SRMC of transmission, i.e., the energy losses.

42. If a transmission constraint emerges that prevents Generator A from serving all of the demand at location B, then the spot prices will diverge even more. Generator B will be called on to dispatch at the higher price of $50/MWh and the spot price in location B will be $20/MWh higher than in location A. The difference in nodal prices will again reflect the SRMC of transmission which, in this instance, reflects the cost of energy losses *and* the opportunity cost of not being able to use the cheapest generation source.

Figure 1 SRMC and Nodal Prices



43. In other words, the spot price at each node will reflect the price bid by the marginal generator (the last generator that is dispatched to serve a location) and the SRMC of transmission. The "unit price" of transmission in the New Zealand market therefore reflects the efficient pricing principle we described above, i.e., it reflects the SRMC of using the existing assets. Moreover, because competing offers provide incentives for generators to bid at their SRMC, demand at each node is typically served at the lowest possible cost.[21]

44. A key challenge for the TPM is therefore to enable Transpower to recover the fixed (non-marginal) costs of its existing network assets in a way that preserves the high level of static efficiency brought about by these locational marginal price signals.[22] An important thing to remember in this respect is that the costs of those existing network assets are "sunk" for all practical purposes (even if not in the strict "textbook" sense). As we explained in our previous report this is because:

- transmission assets are often big, expensive and highly specific, e.g., there are few viable alternative uses for a transmission tower; and
- the costs Transpower will typically incur removing/redeploying an asset consequently tend to be greater than the cash-flow it could receive from the asset once redeployed/sold – often significantly so.

21 We explain this point in more detail in section 4.1 of our economic critique of the EA's proposed TPM methodology. *See:* CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013.

22 This includes the fixed costs of administering them, such as maintenance and salaries. These costs are fixed in the sense that they do not vary with the electrical usage of that asset.

45. Furthermore, the return that Transpower is entitled to earn on its existing assets (and its forecast new capital expenditure) is determined by the Commission as part of a separate regulatory approval process. Before a major new investment can proceed, it must be shown to have (amongst other things) the highest "expected net electricity market benefit".[23] Once an investment has been approved, the efficient commissioned costs form part of Transpower's regulated revenue that it is entitled to recover under the TPM.[24]

46. This returns us to the point that we made in our first two reports: changes to the TPM will have no effect on these past investment decisions. They will neither reduce the cost nor change the nature of those outlays – including because the regulatory arrangements applied to Transpower by the Commission permits recovery of those costs. An important objective of the TPM should therefore be to recover those costs in the least distortionary manner possible, i.e., without overly compromising short term static efficiency.

47. Currently, the recovery of these fixed costs (which comprise the majority of Transpower's regulated revenue) is facilitated through a series of charges that are largely fixed in nature, e.g., levied on the basis of a user's peak demand or injection. The net result is a two-part tariff that closely resembles the efficient "Ramsey-Boiteux" principles we described earlier; namely:

- the SRMC of transmission grid usage is reflected in the differences in wholesale spot prices between nodes; and
- the fixed costs of existing transmission assets are recovered through a series of fixed charges, with a view to minimising distortions to grid usage.[25]

48. This is likely to result in very efficient usage of the existing transmission assets, because:

- the strong incentives for demand to be served at the lowest SRMC (of generation and transmission) promote productive efficiency; and
- demand that can be met at a price that exceeds the SRMC of supplying it will rarely go unserved, promoting allocative efficiency.

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23 Note that this is an altogether different standard to the "private benefits" test proposed by the EA in its Issues and Proposal Paper. *See:* Commerce Commission, *Re Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, 31 January 2012, Schedule D1, p.53. The Grid Investment Test (GIT) previously administered by the Electricity Commission had an equivalent emphasis.

24 The EA appears to recognise this in paragraph 8.13 of its sunk costs working paper.

25 Transmission charges tend to be levied on peak demand or injections, which reduces distortions to the wholesale market and on day-to-day production and consumption decisions. With the limited exception of the HVDC charge, this means that generators' wholesale bids are not influenced by their transmission charges. *See:* CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013.

49. The existing pricing arrangements are therefore likely to result in a high degree of short term static efficiency. This is a key reason why the New Zealand wholesale market is widely regarded as being at the forefront of international best practice.[26] It follows that there is little scope for changes to the TPM to deliver incremental static efficiency benefits. The more likely source of potential benefits is through the promotion of more efficient investment in new assets, i.e., dynamic efficiency.

3.2 Long term dynamic efficiency

50. Hitherto we have explained why the existing TPM, when combined with full nodal pricing, results in very efficient usage of the existing transmission assets in the short term when capacity is fixed. However, in the long run, incremental changes in demand no longer need to be met from current capacity alone. Firms can expand capacity. The link between the SRMC of transmission, the LRMC, and efficient new investment in both transmission network and generation assets reflects that described earlier; namely:

- as demand grows the SRMC of transmission losses and constraints will eventually rise to the point at which it is cheaper to augment the network; and
- it is therefore efficient for new investment to occur when the LRMC of adding capacity is equal to the avoided cost of future constraints and losses – SRMC.

51. The initial thinking in New Zealand was that the existence of full nodal pricing might give rise to market-driven investment. Specifically, like the hotel business described in section 2.3, when confronted with the escalating costs of losses and constraints, network users would invest in new transmission assets; namely:

- users would invest in new transmission capacity when the LRMC of doing so was less than the projected SRMC of future losses and congestion; and
- in return, they would receive a right[27] to any congestion rents, i.e., revenue that arises from a divergence in the spot price between locations.

52. However, as we explained in our first report,[28] there have been no user-driven transmission investments in HVAC or HVDC assets in New Zealand. That is unsurprising when one considers the formidable obstacles presented by the economic characteristics of transmission networks, including the strong economies of scale associated with new investments. These scale economies mean that:

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

[27] Such rights might be "physical rights" to the dedicated infrastructure, or "financial" transmission rights (FTRs) that are purely financial in nature.

[28] CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, pp.43-46.

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- once the land has been purchased and the towers built, there is not much difference in cost between a low and a high capacity line; and so
- high capacity lines are typically build, which eliminate congestion for prolonged periods, rendering any rights to congestion rents worthless during that time.

53. Another challenge is 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). 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). This means that congestion rents tend not to reach the level at which they reflect LRMC of adding capacity – new investment occurs before that point.

54. A fully decentralised "market-based" model can therefore never be solely relied upon to drive transmission investment – decisions must instead be at least partially facilitated through regulation. Currently, the TPM has a strong focus on recovering the costs of existing assets as efficiently as possible – which it does very successfully. However, a number of commentators – including CEG economists[29] – have, raised the possibility of the TPM being modified to signal more clearly the LRMC of future transmission investments.

3.3 Additional LRMC-based price signal

55. Although the existing arrangements result in very efficient usage of the existing grid, one might still consider augmenting those prices to improve the efficiency with which *new* assets are built. The basic reason for this is that, in principle, if grid users do not face the long run costs that their actions impose on the transmission network, they may act inefficiently. Consider a generator that is deciding whether to locate plant in Southland, far away from the nearest load centre, or in Auckland.

56. The long-run cost associated with providing transmission service to the two locations is unlikely to be the same. The Southland plant may cause additional transmission costs to be incurred in the long run, whereas locating the plant in Auckland – New Zealand's largest city – may avoid or defer transmission investment that might otherwise be required. To the extent that this cost differential is not reflected elsewhere, ideally, the TPM would signal that difference to the generator before it invested.

57. Specifically, the overall price difference between the two locations should ideally reflect the LRMC differential that is not already reflected in the nodal price differential, i.e., the "gap" between LRMC and SRMC. If the TPM was modified to signal that difference, then the generator in our example would need to decide

29 *See:* Green., H, et al (2009), *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009.

whether the costs it will save by locating in Southland (e.g., cheaper fuel, lower labour costs) will outweigh the LRMC of transmission, as reflected in the higher transmission prices it will have to pay.

58. If providing the additional signal means that it chose to locate in Auckland, this may be a desirable change in behaviour. This is because future transmission costs may have been reduced by more than the additional costs the generator will now face by altering its investment decision. However, in order for transmission prices to precipitate these changes in behaviour, they must have a *material bearing* on the investment decisions of generators and load. In practice, there are other factors that may have a far greater impact, for example:[30]

- generators will tend to locate their plants based primarily on the availability of certain fuels (coal, gas, water, wind) – this may be more important than any feasible differentiation in transmission prices;[31] and
- the investment decisions of large industrial load will be influenced by many considerations that are likely to be more important to them than transmission charges, including access to markets, the proximity of customers, etc.

59. If these other factors outweigh any feasible differences in transmission charges across geographic locations and/or time, then grid users will continue to invest in *the same way*, and the profile of future transmission investments needed to meet their demand will be unaffected. In these circumstances, there would be no dynamic efficiency benefits from providing the additional LRMC-based price signal – even if it did arguably reflect a more "theoretically correct" approach.

60. To deliver benefits, a change must precipitate a positive change in future investment outcomes. Changes to the TPM that simply alter the incidence of transmission charges to the financial advantage of one party or another, but do not produce any changes to investment outcomes, impose administrative costs with no offsetting benefits. Every CBA framework must therefore express a coherent link between a change in price and the creation of new, superior investment outcome.

61. Even if it is theoretically possible for an enhanced price signal to achieve such an outcome, there are a number of additional practical complications that would need to be overcome. For example, it is extremely difficult to provide a robust signal of the LRMC of future transmission expansions. One of the reasons for this is that the LRMC of the transmission capacity changes over time in the manner described earlier in this report:

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30 For a more comprehensive discussion of these matters, *see:* Green., H, et al (2009), *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.12.

31 Investment decisions can also be influenced by pragmatic considerations such as the need to obtain the appropriate consents under the *Resource Management Act 1991*.

- in the years immediately following a new investment the LRMC of the next increment to capacity is low, and so an LRMC-based price would therefore tend to encourage the use of that infrastructure; whereas
- as the need to invest in new capacity approaches the LRMC of the next capacity expansion increases, and an LRMC-based price would discourage the use of that infrastructure, thereby delaying the imminent need for new capacity.

62. In designing any price signal it is therefore likely to be necessary to come to a view on where one might feasibly introduce a *durable* signal that will not need to be regularly changed as market circumstances develop – assuming that constant volatility is undesirable. However, the inevitable consequence of any averaging is that the resulting price signals will under- or over-state the true LRMC at any point in time (as well as the SRMC of transmission, as we explain below).

63. Moreover, because LRMC oscillates through time, so too do the benefits that any such price signal can deliver. If new investment is not going to be needed for many years, the benefit of pushing back those future capacity expansions is likely to be small in present value terms. The dynamic efficiency benefits that are potentially achievable through changes to the TPM therefore depend critically on the point in the investment cycle.

64. It must also be remembered that the attainment of any such benefits will not be costless. As we noted already, if changes to the TPM cause generators or load to alter their investment plans, the costs to them of doing so – more expensive fuel, higher wages and so on – must be weighed against any benefits. One must also consider whether distortions might be imposed on the wholesale market and on day-to-day production and consumption decisions, with attendant negative effects on short term static efficiency.

65. This latter point is particularly important. We explained above that the "unit price" of transmission reflects the SRMC of using the existing assets, and that the recovery of fixed costs appeared to be achieved with only limited distortions. If the TPM is reformed so that the unit prices paid by generators and load instead reflect some measure of LRMC, this is likely to systematically over- or under-state the SRMC of transmission, compromising short-term static efficiency.[32] In short, there are myriad trade-offs that must be assessed.

3.4 Summary

66. The analysis set out above provides a strong indication of where the potential benefits from transmission pricing reform might lie. First, it established that there

32 However, those inefficiencies might be reduced (perhaps avoided altogether) if the signal is provided by way of a fixed charge that did not result in distortions to short-term production and consumption decisions, once an investment decision had been made.

are unlikely to be any material benefits in the form of improved static efficiency. The simple reason for this is that the costs of the existing assets are recovered through the imposition of a relatively efficient two-part tariff, where the variable component reflects the SRMC of transmission grid usage. Put another way, there appears to be "little more work" for the TPM to do in this respect.

67. If there are any potential benefits of transmission pricing reform, they must therefore lie in the promotion of more efficient investments, and enhanced long term dynamic efficiency. However, the realisation of those benefits depends critically upon a number of practical matters. For example, it depends upon whether a robust price signal can be designed – a challenging task given the time dependent nature of LRMC. It also depends upon whether such a signal will have a material effect on investment decisions, which it may not if:

- generators locate their plants based primarily on the availability of certain fuels, such as coal, water, gas and wind; and
- major users locate based on factors such as access to markets, the proximity of customers, rent and labour costs, etc.

68. The point in the investment cycle is also a critical consideration. If the next major expansions are not scheduled to take place for many more years, then the benefit of deferring those investments through transmission pricing will be small in present value terms. Finally, any benefits must be weighed against the attendant costs, of which there will be many. As we explain in the following section, in the context of the existing transmission pricing and investment framework, these factors suggest that there is little scope to achieve dynamic efficiency benefits.

4 Implications for the CBA Framework

69. In this section, we consider the extent to which the EA's CBA working paper reflects the conclusions in the previous section. In our opinion, it does not. In particular the EA suggests that it may be possible to change the TPM in a way that delivers both static *and* dynamic efficiency benefits. Although the EA does not explain how it would change the TPM,[33] the assumption is that "remote generators" will face "higher transmission costs" and "within-region generators" will face "lower transmission costs".[34] It contends that one of the impacts of these changes over time would be to:[35]

> *"…decrease dispatched output from generators with a high reliance on now higher cost transmission services, and increase output from generators with a low reliance on now lower cost transmission services. There would be an increase in productive efficiency because the same output would be produced with fewer inputs. The effect would be to reduce the aggregate delivered costs of electricity…"*

70. In our opinion, the sentiments expressed in the extract above conflate several concepts. For example, although the EA speaks of generators relying on transmission services with higher and lower *costs*, it appears to really mean *prices*. Specifically, the contention seems to be that, if the price of transmission links used by "remote generators" increases and this causes consumers to switch to now lower priced "within-region generators", then this may give rise to static efficiency benefits. We disagree.

4.1 Potential for static efficiency benefits

71. The EA's proposition that static efficiency improvements are attainable through transmission pricing reform appears to rest on circular logic. The reason that consumers are switching to "within-region generators" in its example is because relative *prices* have changed. However, it is important to recognise that the underlying *costs* of providing the transmission and generation assets have not. There is therefore no reason to think that static efficiency will be enhanced. In fact, it is more likely that static efficiency will have been compromised by such changes.

72. Consider again the example depicted in Figure 1. Generator A is connected to the larger load centre (at location B) via a transmission line (a "remote generator") and generator B is connected directly (a "within-region generator"). Generator A is

33 This will presumably be canvassed in more detail in subsequent working papers.

34 CBA working paper, §6.14.

35 CBA working paper, §6.15.

capable of serving 100% of the demand at location B, and can do so at a lower cost (accounting for transmission losses) than generator B. As we explained earlier, under the current market arrangements, if both generators bid their SRMC, generator A will be dispatched, and the nodal price at the load centre will reflect that SRMC plus the cost of transmission losses.

73. For the reasons described above, this is likely to result in a high degree of static efficiency. There are few, if any, gains to be made. Adjusting the TPM so that generator A (the "remote" generator) pays a higher price for the transmission link in the manner contemplated by the EA will not improve static efficiency – it will compromise it. If generator A now faces higher variable charges whenever it generates – e.g., because it must pay a transmission charge reflecting its deemed private benefit – two outcomes are possible:

- it will increase its bids to reflect costs that were once fixed, but are now marginal, resulting in higher spot prices at the load centre; or
- if it cannot feasibly reflect those higher costs in its bids, it may go out of business, stranding the plant and, potentially, the transmission line.[36]

74. In either scenario, static efficiency may be reduced. In the first, the imposition of the new variable charge increases the opportunity cost of generating, and may result in higher spot prices. As we explained in our first report,[37] this need not reduce static efficiency in the generation sector if all generators' costs are more or less equally (proportionally) increased.[38] In those circumstances, the generation "merit curve" would shift up, but its shape would not be affected.

75. However, if different generators are affected differently by the proposal, then both the level *and* the shape of the generation merit curve will be distorted. This will compromise static efficiency, because the net effect will be that some generators are dispatched when they have a higher "true" SRMC than other generators not dispatched. The "private benefit" charge proposed by the EA in its first issues paper would have had such an effect.[39]

76. In the second, there is the additional detriment of unrecovered costs, i.e., the cost of "asset stranding". Given the degree of asset specificity, it may not be possible to economically sell or redeploy the stranded transmission and generation

36 The EA acknowledges that a potential consequence of changing the TPM may be unutilised transmission or generation capacity. *See:* CBA working paper, footnote 13, p.15.

37 CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, pp.32-33.

38 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).

39 *See:* CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, §113.

infrastructure. For example, the costs that would be incurred removing/redeploying the assets may be greater than the cash-flow the firms might expect to receive from the assets once they have been redeployed/sold.[40]

77. Any analysis of the costs and benefits of such price changes must account for these potential static efficiency costs. The EA's CBA framework must therefore explicitly account for the fact that:

- a significant proportion of the grid is sunk for all practical purposes (even if not in the strict "textbook" sense[41]) and can therefore be used to transport electricity at low SRMC (and LRMC); and
- if unit prices depart significantly from SRMC risk this may result in the underutilisation of existing infrastructure and distort production and consumption decisions.

78. As it is currently framed, the EA's CBA framework does not adequately account for these matters. It instead reflects the misconception that changing the TPM can result in material static efficiency improvements. For the reasons set out above, there is, in fact, very little scope for incremental static efficiency improvements. Put simply, the potential benefits from transmission pricing reform do not lie in the form of static efficiency improvements and this must be reflected in the EA's CBA framework.

4.2 Potential for dynamic efficiency benefits

79. The EA's description of the potential sources of long term dynamic efficiency benefits is more orthodox, as is its proposed approach to estimating the present value of those benefits. In particular, it correctly recognises that dynamic efficiency benefits might be obtained if a new price signal changes production and consumption patterns in a way that reduces the total cost of delivering electricity in the long term. The following extract from the CBA working paper expresses this rather succinctly:[42]

> *"…if changes to the TPM have the intended efficiency impact, then it could lead to significant changes in the transmission planning outlook. The forecast requirement for (now) inefficient transmission capacity augmentation could be deferred and reduced. Conversely, the forecast requirement for (now) efficient transmission augmentation could be increased and brought forward."*

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40 For a more comprehensive explanation, *see:* CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013, p.5.

41 *Ibid*, pp.4-6.

42 CBA working paper, §6.21.

80. As we explained above, dynamic efficiency benefits might be achieved if transmission prices were augmented to provide a signal of the forward-looking LRMC of providing the service in question. For example, in our earlier example, we explained how the TPM might signal to the generator the difference in long run transmission costs between it locating in Auckland or in Southland. Recall that providing such a signal might cause a desirable change in behaviour (i.e., the generator locating in Auckland) that reduced future transmission costs by more than the additional costs it would face by altering its investment decision.

81. In other words, while we do not agree that modifications to the TPM can deliver material static efficiency benefits, we accept that, in *principle*, dynamic efficiency benefits might be achievable. However, there are a number of *practical* obstacles that would need to be overcome before a CBA framework could reasonably conclude that those benefits existed, and could be achieved without giving rise to additional costs that outweighed them.

82. First, as the EA recognises,[43] it is important for the CBA framework to establish a *causal relationship* between a change to the "status quo" and the attainment of a benefit. To establish that link, it is first necessary to show that changing the TPM can produce a *material change* to investment outcomes. Those changes might involve Transpower (or generators or load) investing in different asset, or in a different location, or at a different time.

83. If changing the TPM has no discernible effect on future investment outcomes, then there can be no dynamic efficiency benefits with the CBA framework. In other words, changes to the TPM that simply alter the incidence of transmission charges to the financial advantage of one party or another, but do not produce any changes to investment outcomes, do not produce dynamic efficiency benefits. The same outcome is achieve "with and without" the change.

84. To illustrate, suppose for the sake of argument that there was an unambiguously "perfect" TPM. Intuitively, one might expect that it would be beneficial to move to such a model. However, a CBA framework cannot *assume* that is the case – it must test it *empirically*. If it turns out that all market participants were likely to invest in exactly the same way, regardless of whether the "perfect TPM" was employed, then it would offer not dynamic efficiency benefits relative to the status quo. However, there are likely to be administrative costs associated with the change.

85. In other words, in order for changes to the TPM to deliver dynamic efficiency benefits, transmission prices must be capable of effecting investment decisions *in a material way*. Before a change to the TPM can influence future transmission investment outcomes, it must first affect the investment decisions of generators and load. However, as we noted above, in practice, there are several other factors that

43 CBA working paper, §8.1.

are likely to be of much greater significance to the investment decisions of generators and load than transmission prices. For example:[44]

- generators will tend to locate their plants based primarily on the availability of certain fuels (coal, gas, water, wind) – this may be more important than any feasible differentiation in transmission prices;[45] and
- the investment decisions of large industrial load will be influenced by many considerations that are likely to be more important to them than transmission charges, including access to markets, the proximity of customers, etc.

86. If these other factors outweigh any feasible differences in transmission charges across geographic locations and/or time, then grid users will continue to invest in the same way, and the profile of future transmission investments needed to meet their demand will be unaffected. For these reasons, it may be difficult to establish the requisite relationship between changes in the TPM and the investment decisions of generators, load, the Commission and, ultimately, Transpower. However, establishing such a link is necessary part of any coherent CBA framework.

87. Second, even if it could reasonably be established that changing the TPM has the potential to affect investment outcomes – the effect must also be shown to be *beneficial*. If a dynamic efficiency benefit can be obtained, then it follows that there must be a certain level of dynamic inefficiency associated with the existing investment and pricing framework. Indeed, the only way that a dynamic efficiency benefit can be obtained is through avoiding a dynamic inefficiency *cost*.

88. It has not been suggested (at least not explicitly) that the Commission's capital investment framework 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",[46] or that the investment framework will lead to it doing so in the future. It is consequently unclear where dynamic efficiency benefits would flow from in the event that investment outcomes could feasibly be altered (which is also unclear).

89. The point in time in the investment cycle is also likely to mean that if benefits can in fact be achieved, they are likely to be modest. The reason is that Transpower has just completed (or will soon complete) a $2 billion investment programme. Far fewer investments will be made, moving forward, and so the potential benefits from

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44 For a more comprehensive discussion of these matters, *see:* Green., H, et al (2009), *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.12.

45 Investment decisions can also be influenced by pragmatic considerations such as the need to obtain the appropriate consents under the *Resource Management Act 1991*.

46 For example, the EA does not seem to question directly the efficiency of the $2 billion in investments that was approved recently.

altering future investment outcomes (i.e., deferring future costs[47]) are likely to be relatively modest in present value terms.[48]

90. Third, even if the existing investment and pricing arrangements have the potential to result in material levels of dynamic inefficiency, that problem can only be addressed with the *right* price signal. For example, the TPM might be modified so as to signal to grid users the LRMC of their actions on future transmission requirements. The basic idea would be to convey to customers: *"this is the additional cost that I will incur in the long run if you 'do X', and so that is the price that you must pay if you do that"*. However, modifying the TPM to reflect the EA's "beneficiaries-pays" approach would not provide such a signal.

91. The EA's proposed approach would signal to customers: *"this is how much I perceive you to be benefiting from this particular service, and so I will charge you a price that reflects that, regardless of the existing costs of supplying it, or the LRMC of expanding capacity in the future"*. In essence, the EA's methodology seeks to estimate how much parties would be prepared to pay to avoid a particular asset being taken away. Such questions have no obvious role in the establishment of efficient prices for services provided using existing fixed assets.

92. This is especially the case in the period following the addition of new transmission capacity. Because such investments tend to eliminate congestion for prolonged periods, the SRMC of congestion and the LRMC of the next expansion will be very low, and so one might reasonably expect unit prices to also be low to encourage the use of that infrastructure. However, under the EA's proposal, if a party is deemed to be place a high private value on an existing asset (i.e., to avoid it being "taken away"), it may end up paying a "usage" price that:

- exceeds the SRMC of using the transmission network, compromising short term static efficiency; and
- exceeds the expected LRMC of the next capacity expansion (which is many years away), compromising long term dynamic efficiency.

93. Put simply, there is no reason to think that the private benefits that market participants receive from the use of existing transmission assets today will reflect either the SRMC of using the grid, or the LRMC of adding capacity in the future. Any such equivalence would be pure coincidence. Setting prices for existing assets

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47 For example, the costs saved by deferring by 5 years an investment that would otherwise be made in 50 years will be much lower in present value terms than deferring an investment that would otherwise be needed tomorrow.

48 This was the principal reason why the tilted postage stamp methodology considered by the CEO forum was ultimately not recommended. Because Transpower had recently committed to several large investments, those costs could no longer be avoided, reducing the potential benefits of modifying the price signal.

by reference to private benefits therefore promotes neither short term static efficiency nor dynamic efficiency.

94. The more likely scenario is that it will compromise the achievement of both. For example, as we have explained in some detail in our previous reports,[49] if the EA's "beneficiaries-pay-in-proportion-to-benefit" proposal – or some variant of it – is implemented, this will give rise to the following costs that would need to be weighed within the CBA framework:

- the costs of disputes and litigation will increase substantially if the proposal is introduced – these additional costs would need to be factored into any quantitative modelling;
- static efficiency losses will arise from distortions to the dispatch process brought about from the conversion of previously (predominantly[50]) fixed transmission charges into potentially volatile variable tariffs; and
- the heightened risks produced by the proposal may reduce the degree of retail competition – particularly that offered by smaller retailers without "natural" hedges – the attendant harm to efficiency would also be important to consider.

95. In our opinion, there is strong reason to think that these costs would outweigh the long term benefits if the EA's "beneficiaries-pay" principle is implemented. Indeed, our consideration of the practical factors described above suggests that the potential for changes to the TPM to deliver material improvements in dynamic efficiency is likely to be very limited, but there is a clear prospect of significant additional costs. The EA's CBA framework should therefore reflect these relative probabilities.

49 *See:* CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, pp.20-43 and CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013, pp.1-4.

50 There is an element of variability in both the HAMI and RCPD charges.

5 Conclusion

96. The EA's CBA framework currently reflects its belief that changing the TPM can result in material static efficiency improvements. In our opinion, that belief is misplaced. The existing pricing arrangements signal to users the SRMC of using the grid and appear to recover the fixed (non-marginal) costs of the existing assets with relatively few distortions. They are therefore likely to result in very efficient usage of the existing grid, leaving little scope for incremental improvements.

97. The more likely source of *in principle* benefits from transmission pricing reform lies in the promotion of more efficient investment in *new* assets in the long term, i.e., through the enhancement of dynamic efficiency. However, there are a number of factors that suggest that this is also an unlikely source of potential benefits *in practice*. First it is unclear whether any reasonably conceivable change in the TPM will have a significant effect on investment outcomes, given that:

- generators locate their plants based primarily on the availability of certain fuels, such as coal, water, gas and wind; and
- major users locate based on factors such as access to markets, the proximity of customers, rent, inputs and labour costs, etc.

98. Second, even if changing the TPM could materially change investment outcomes, it is unclear whether material dynamic efficiency benefits could be obtained, since:

- it has not been suggested that the Commission's capital investment framework is incapable of delivering the right investment outcomes; and
- the benefit of deferring future investments through transmission pricing is likely to be small, given the point in time in the investment cycle.

99. Third, although dynamic efficiency benefits might be achieved in *principle* by signalling the LRMC cost of future investments, in *practice*:

- designing a robust price signal is extremely challenging, given the time dependent nature of LRMC;
- the "beneficiaries-pay" approach proposed by the EA in its first options paper does not reflect LRMC; and
- the signal actually provided has no obvious role in the establishment of efficient prices for services provided using existing fixed assets.

100. Finally, any dynamic efficiency benefits would need to be weighed against the attendant costs, of which there will be many, including:

- the costs of disputes and litigation, which will increase substantially if the proposal is introduced;

- the static efficiency losses arising from distortions to the wholesale generation dispatch process; and
- the potential efficiency costs associated with any reduction in retail competition brought about from the heightened risk produced by the proposal.

101. The potential for changes to the TPM to deliver material improvements in dynamic efficiency is therefore likely to be limited in practice, but there is a clear prospect of significant additional costs. We therefore remain of the opinion that, if the EA's preferred pricing reform remains a "beneficiaries-pay" approach applied to both new and existing assets a quantitative CBA is not needed to see why the proposal is unlikely to promote either static or dynamic efficiency.