COMPETITION ECONOMISTS GROUP

Economic Review of EA Beneficiaries-Pay Options Working Paper

A REPORT FOR TRANSPOWER

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Executive Summary

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) beneficiaries pay options working paper.[1] That paper sets out the EA's revised options for applying "beneficiaries-pay" approaches to recover the costs of HVDC and interconnection assets under the transmission pricing methodology (TPM). It reflects certain shifts in the EA's thinking since it proposed the scheduling, pricing and dispatch (SPD) model approach in its October 2012 issues paper.[2]

2. CEG considers that the new simplified SPD charge option is an improvement upon the SPD charge the EA originally proposed. Nonetheless, there are material problems with all four of the new options, i.e., the simplified SPD charge, the GIT-plus-SPD and SPD-plus-GIT charge, and the zonal SPD option. Many of these problems are the same or similar in nature to those we identified with the EA's original proposal. In our opinion, the principal sources of allocative and dynamic benefits cited by the EA are unlikely to transpire. Moreover, if implemented, the options have the potential to give rise to significant inefficiency costs.

3. The reasons the EA has offered for levying the SPD charges on retailers as opposed to distributors also appear to be unsound. The problems that distributors would have faced managing the volatility and uncertainty of the SPD charges as originally proposed (i.e., a charge applied ex post and measured on a half-hourly basis) would be ameliorated by the new options (which are applied on an ex-post basis). With those issues having been addressed, there would now be no other meaningful benefits from charging retailers, but there would be material additional costs.

Allocative Efficiency

4. The EA contends that all of its revised charging options would promote allocative efficiency by reducing deadweight loss. In our opinion, it is unlikely that these options would have such an effect. The use of the existing grid appears be relatively efficient under the current TPM, which results in what appears to be a relatively efficient two-part tariff. We would therefore not expect there to be a substantial level of inefficient unserved demand in the market at present.[3]

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[1] Electricity Authority, *Transmission pricing methodology: Beneficiaries-pay options, Working paper,* 21 January 2014 (hereafter: "Beneficiaries pay working paper").

[2] Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012.

[3] We provided a more comprehensive qualitative assessment of the extent to which the existing TPM is likely to promote static efficiency in our report in response to the EA's CBA working paper, *see:* CEG *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §3.1.

5. It follows that there is no material prospect for allocative efficiency gains to be achieved by implementing the new options – and the large welfare neutral transfers that they would inevitably entail should not be confused as such. Moreover, even if material gains were thought to be achievable (which we do not consider to be the case), these must be weighed against the distortions to efficiency that would arise from the challenges entailed in estimating benefits via the SPD methodology.

6. The methodology calls for the quantification of a large number of parameters that are used to estimate each party's private benefit. In addition to greatly increasing the likelihood of ongoing disputes over transmission charges, there is also the potential for allocative inefficiencies to arise if the methodology fails to accurately estimates parties' private benefits (e.g., by overstating the cost of non-supply) and causes them to reduce their demand – albeit perhaps only at the margin. In our view, there is no *a priori* reason to believe that these distortions would be any less significant than those thought to be associated with a residual charge.

7. Moreover, the *time profile* of SPD-based charges would cause further inefficiencies. In any year, the quantum of the SPD-based charges applied to an asset cannot exceed the revenue that Transpower is permitted to recover for those investments under its individual price-quality path (IPP). Because Transpower applies straight-line depreciation under its IPP, this means the potential total quantum of SPD-based charges for an asset (i.e., the "capped" amount of revenue that can be recovered via the charge in each year) are likely to be:

   - highest immediately after an asset has been built, i.e., when no straight-line depreciation has been applied; and
   - lowest right at the end of its estimated economic life, i.e., when it is fully depreciated and scheduled to be replaced.

8. Conversely, if there is spare capacity immediately after the asset is built that is reduced over time as demand grows (which is commonplace, given the strong economies of scale typically associated with transmission investments), the potential private benefits parties derive from the investment would increase over time. The EA's methodology for the SPD charge is therefore likely to produce the counterintuitive outcome whereby prices are at their highest when:

   - the long-run marginal cost (LRMC) is lowest, i.e., when there is ample spare capacity and the replacement cost of a new asset is some way off;[4] and

[4] In the time period immediately following a capacity replacement/expansion (i.e., those following t_1 and t_2 in Figure 1) the forward-looking cost of the next increment to capacity is low, because the value of any potential deferral of that future capacity requirement is relatively low due to the effect of discounting. As spare capacity declines over time and the need to invest in new capacity approaches (i.e., the time periods leading up to t_1 and t_2), the present value of the cost of the next increment to capacity increases, because the value created through any potential deferral is closer in time and so less (negatively) affected by discounting.

- the aggregate private benefits that parties are deriving from the existing asset are lowest because of the significant spare capacity, i.e., demand is low.

And at their lowest when:[5]

- the LRMC is highest, i.e., when congestion is occurring and the replacement cost of a new asset is imminent; and
- the aggregate private benefits that parties are deriving from the existing asset are highest – *precisely because* the next expansion is looming.

9. The charge would therefore result in an *inverse relationship* between the revenue to be recovered through SPD-based prices and both short- and long-run marginal cost, as well as aggregate private benefits. Namely, in the early years of an asset's life the charge would seek to recover the greatest amount of revenue from the fewest number of customers. As the asset ages, the methodology would seek to recover less and less revenue from more and more customers – encouraging them to make even greater use of already capacity-constrained infrastructure.

10. This profile of cost recovery is the antithesis of what efficient transmission pricing requires. The most efficient pricing of transmission assets would typically involve lower prices in the *early years* of an asset's life to encourage demand and the highest SPD-based prices *immediately prior to* the new asset being built. The economic logic is that efficient pricing is intended to signal the forward-looking cost of usage to consumers so that those who do no value the service sufficiently can alter their behaviour and the costs can be avoided or deferred.

11. The appropriate time at which to send these signals about the cost of incremental usage is *before* fixed and sunk costs are incurred. In the years immediately following a new investment, the short- and long-run marginal cost of additional demand is "low", since the cost of the next expansion is modest in NPV terms.[6] This means that prices should be "low" all things being equal. Conversely, when a new expansion is imminent, the short- and long-run marginal cost of additional demand is very high indeed,[7] prices should be "high" to signal those costs.

12. The proposed SPD charge would consequently not necessarily reflect either private benefits or forward-looking costs and would provide highly inefficient price signals to grid users. It would mean that there are customers that choose to use a transmission asset at an SPD-price based on its depreciated historic cost, who would not demand as much of the service if the charge was based on the forward-

5 This would be exacerbated by the daily cap which would restrict the revenue the SPD charges could recover during peak usage periods, i.e., the periods that are driving the cost of the transmission grid.

6 This is because the cost of bringing forward by, say, one year, an investment that would otherwise have taken place in 50 years is relatively modest in NPV terms compared to the cost of bringing forward to today the cost of an investment that would otherwise have taken place in 2 years.

7 *Ibid.*

looking replacement cost of a new asset. This would distort consumption patterns and compromise allocative (and dynamic) efficiency.

13. The GIT based charges may cause further problems. It should not necessarily be assumed that the quantum of private benefits for these assets exceed the investment cost. Under section III of the *Electricity Governance Rules*, a reliability investment would be approved if it was necessary to meet applicable grid reliability standards and maximised the expected net benefit compared with alternative projects, with the proviso that the expected net benefit *could be negative*.

14. The effect of the proviso is that the cost of a reliability investment might well exceed the expected net benefit (unlike for an "economic investment"). Assigning the cost of reliability investments to load might therefore conceivably result in them paying charges that exceed their private benefits. This is made even more likely by the fact that load in a particular location will never be the only "private beneficiaries" of reliability investments, for example:

    - generators in certain locations would, by definition, also benefit, since some would receive higher prices than would otherwise have been the case; and
    - load in locations outside the charging area may also benefit, e.g., customers in the Waikato and the Bay of Plenty may benefit from the NIGU project.

15. The methodology also does not identify the "causers" of reliability investments, e.g., although load in the far north are classified as "beneficiaries" of the NIGU project, they cannot reasonably be said to have caused the need for it. The GIT-based charges' approach of assigning the cost of reliability investments to load might therefore result in them paying charges that exceed their private benefits, with potential attendant distortions to allocative efficiency.

16. Finally, if market participants are aware of the methodology that would be used to assess the extent of their private benefits they would have an incentive to change their behaviour in ways that reduces the extent to which they are estimated to benefit. Most notably, generators may seek to reduce the extent to which they are perceived to benefit from transmission assets by increasing their bids above short-run marginal cost (SRMC) – something that they have little (if any) incentive to do under the current TPM.

17. In doing so, generators would seek to optimise the trade-off between lowering transmission charges (by bidding above SRMC) and increasing the probability of not being dispatched, with the attendant negative effects on their profitability. If this conduct is widespread then, at best, it would distort the estimate of benefits under the Authority's model. At worst, it would seriously compromise the efficiency of the wholesale dispatch process and lead to higher prices.

18. There are some clear parallels here to the well-recognised inefficiencies that would be likely to arise if the *wholesale* prices that generators were paid were to be based

on their bids (a "pay-as-offered" approach) as opposed to the highest offer required to satisfy demand. Such an approach was subjected to a compelling criticism by the Chair of the EA, Dr Brent Layton, in his paper *The Economics of Electricity*.[8] Dr Layton pointed out that such an approach would lead to:

- bids above SRMC and out-of-merit dispatch; and
- higher cost generation than is necessary and higher costs for society.

19. This criticism could also be applied to the EA's proposed SPD charge, which would *also* result in generators paying charges based on their wholesale bids – in this case their transmission charges. The charge can therefore reasonably be characterised as an "indirect" form of pay-as-offered pricing. It follows that it can be expected to give rise to *exactly the same distortions* that Dr Layton cautions against in his paper, and which we described above.

Dynamic Efficiency

20. The EA appears to believe that its SPD options would enhance dynamic efficiency by improving the process by which the Commerce Commission (Commission) administers its Investment Test for electricity transmission. It claims that if parties must pay directly for the investments from which they benefit, they would have a greater incentive to participate in the process. The EA presumably believes that this would produce *superior information* than is the case under the current TPM, which would make it easier to identify those investments that would maximise the net present value of market benefits ("good" investments) and those that would not ("bad" investments).

21. In our opinion, that belief is misplaced. First, as we explained in our first report,[9] the EA is yet to provide any material to suggest that the Commission's input methodology (IM) has not facilitated efficient investment outcomes – or that it is incapable of doing so in the future without the proposed TPM reforms. In other words, the EA has not established that there is a problem with the Commission's new investment framework that needs to be solved.

22. Second, even if there was a problem arising from asymmetric information, the EA's transmission pricing options would not address it. Under both the current TPM and the EA's options there would be a range of submissions in response to a new investment proposal – some in favour, some opposed. Those submissions would be motivated in almost every case by the effect of wealth transfers, not efficiency gains. The only way that the TPM can give rise to a situation where stakeholders only strongly advocate for and against the appropriate projects is when:

8 Layton, B., (2013) *The Economics of Electricity*, 4 June 2013, §8-10.

9 CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, §3.1.

- for NPV positive investments,[10] the beneficiaries pay not only for the project, but also *fully compensate the losers* to stop them opposing it; and
- for NPV negative investments, the potential losers *pay the potential beneficiaries* to stop them from supporting it.

23. Putting aside the obvious practical estimation difficulties, the amount of money that would need to cycle through the TPM to achieve the former might need to be much greater than Transpower's actual revenue requirement. Moreover, there is no obvious regulatory mechanism to achieve the latter – achieving a universal voice of opposition would instead require side-payments between "winners" and "losers". Without these forms of compensation (which the EA is not proposing):

- there would never be a unanimous opinion amongst submitters – there would always be a range of submissions for and against every investment;
- submission would not be motivated by what is best for the market – profit-driven firms will want the outcomes that deliver the most benefits *to them;* and
- the TPM cannot "reveal" the efficient outcome – the Commerce Commission must make that judgement using the criterion in its input methodology.

24. For that reason, we see no basis for the EA's belief that its options would overcome any problems arising from asymmetric information (to the extent they were material) and lead to superior investment outcomes. At best, they would have no effect on future investments – the submissions before the Commission would reflect the usual cacophony of voices. However, the EA's options may make matters *worse* by giving parties greater incentives to oppose beneficial investments and/or to lobby for less beneficial investments for strategic reasons.

25. First, recall that the GIT-based charges involved assigning the costs of certain reliability investments to parties that are not the sole ex-ante beneficiaries, the sole causers or the sole ex-post beneficiaries. We noted above that this might therefore result in them paying charges that exceed their private benefit. If that is likely to be the case under a future investment proposal, those parties can be expected to oppose it, even if it is efficient.

26. Second, the design of the SPD-based charge may further compromise the approval process for new investments. When deciding whether to support an efficient investment, a party will naturally consider whether it will benefit *more* from a *different* investment, such as:

- a smaller investment that entailed lower costs; and/or
- an investment that took place at a later date when demand may be higher.

10 That is, investments that maximise the net present value of net market benefits.

27. The time profile of the SPD-based charge means that parties may derive significantly greater private benefits from smaller, later investments. This is a product of the inefficient time profile of the charge that we described above. Recall that, over time:

- the total SPD-based charges to be recovered (the "cap") from all private beneficiaries in any year decreases, due to straight line depreciation; and
- the total quantum of private benefits from the asset in any year starts to increase due to increased demand, i.e., reduced spare capacity.

28. Once the latter is greater than the former, the TPM would no longer be taking away 100% of parties' private benefits. They would instead be paying for a "smaller slice of a smaller pie". Parties may therefore have an incentive to lobby for investments for which this inflection point *would come sooner*. This means that even if a party would be a private beneficiary of, say, a proposed $100m investment that would maximise overall market benefits, it may still have an incentive to oppose it.

29. The party might expect that, say, a $75m investment that proceeds at a later date would deliver it even greater private benefits, due to the design of the SPD charge. In other words, like the GIT-based charging options described above, the SPD-based charge may serve to push *even more* parties into the camp opposing "good" investments – *including the net beneficiaries*. The reason for this is that those net beneficiaries would not be asking themselves:

- "Is this investment the best outcome for the market?" but rather
- "Is this investment outcome the best outcome for me, or could my benefits be even higher if something else was built and/or at another time?"

30. It would consequently be left to the Commission to determine whether an investment should proceed, based on its assessment of what is best for the market. Throughout its consultation process, the EA has not provided any compelling reasons why its options would make this process any easier or lead to superior investment outcomes. For the reasons described above, those options may actually make the Commission's task *more difficult* and risk inefficient outcomes.

31. Potentially even more problematically, if the increased opposition led to Transpower being made to delay expenditure and/or building smaller assets, there is a risk that the EA might view this as evidence of its reform *working*. It might surmise that the "stronger incentives" it had created for beneficiaries to participate in the investment process had revealed that Transpower was proposing to build things "too big and too early".

32. It might consequently conclude that its revised pricing methodology had prevented those inefficient investments from proceeding, giving rise to substantial dynamic efficiency gains. However, the reality may be quite different. For the reasons described above, the EA's reforms may have instead given parties stronger

incentives to *advocate against efficient investments*, leading to the wrong things being built at the wrong time and substantial dynamic efficiency *losses*.

Charge Retailers or Distributors?

33. The EA preliminarily concludes that it would be better to make retailers subject to the SPD charge rather than distributors. The principal advantages are said to be their "greater familiarity with wholesale market" and their "greater incentive to scrutinise transmission costs because of the lack of a mandated ability to pass through transmission charges." In our opinion, that reasoning is unsound, because:

- whether retailers pay transmission charges directly or indirectly (i.e., via a distributor) should not influence materially their incentive to scrutinise transmission costs – all that matters is whether they ultimately pay;
- it is likely to overstate the difference between retailers' and distributors' incentives to scrutinise transmission costs in any event, since both are likely to be in a position to pass-through 100% of transmission costs;
- retailers appear to have been scrutinising transmission proposals for years even though they do not directly pay transmission charges to Transpower – as have distributors, despite transmission charges being "pass-through" costs;
- it does not matter whether distributors understand the SPD method, or how the wholesale market operates – what matters is whether they can forecast charges with reasonable accuracy; and
- the changes that the EA has proposed to its approach – particularly the move to a more predictable, less volatile ex-ante charge should enable distributors to better predict transmission charges.

34. Charging retailers instead of distributors would therefore seem to offer no obvious benefits. However, there would be costs. Most notably, Transpower would need to enter into a series of new contracts with retailers for the use of the transmission system. This would entail significant additional transaction costs both to Transpower and to retailers. Moreover, as we noted in our first report, the EA's proposal would heighten risks for retailers – disproportionately so for smaller retailers without "natural hedges".[11] Charging retailers is therefore likely to entail additional costs for no clear benefits.

[11] CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, §5.2.

1 Introduction

35. 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) beneficiaries pay options working paper;[12] i.e., the simplified SPD charge, GIT-plus-SPD, SPD-plus-GIT and the zonal SPD option. Although the EA has made some material changes to its original proposal[13] to address certain concerns, it is telling that all of these options utilise the SPD approach for determining charges for some assets. The EA also seems intent upon applying its approaches to existing sunk assets[14] as well as new assets, despite the distortions associated with doing so identified by many submitters, including ourselves.[15]

36. Although the costs and benefits the EA identify vary between options, two principal sources of efficiency benefits are said to arise from:

- recovering a greater proportion of transmission costs from "beneficiaries" and a smaller slice from "non-beneficiaries", which it is claimed would reduce deadweight loss and enhance allocative and productive efficiency; and
- placing stronger incentives on parties identified as beneficiaries to participate in the investment decision-making process, which it is said would produce superior investment outcomes and promote dynamic efficiency.

37. Transpower has asked for our opinion on the likelihood of the EA's revised options giving rise to these benefits, if implemented. In our opinion, these options would not deliver these benefits and would instead give rise to significant allocative and dynamic inefficiency costs. We explain why in the body of this report. We also address certain other specific elements of the options of particular interest to Transpower, including the EA's preference for charging retailers rather than distributors. The remainder of this report is structured as follows:

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12 Electricity Authority, *Transmission pricing methodology: Beneficiaries-pay options, Working paper,* 21 January 2014 (hereafter: "Beneficiaries pay working paper").

13 Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012.

14 As we explained in our response to the EA's sunk cost working paper, whilst one can quibble about the precise theoretical definition of sunk costs versus fixed costs, the vast majority of transmission assets are sunk for all practical purposes and so we continue to use that terminology throughout this report. *See:* CEG, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper,* 12 November 2013.

15 Although the beneficiaries-pay working paper states that the treatment of existing assets will be considered in light of submissions on the sunk cost working paper, the beneficiaries-pay working paper nevertheless details proposals for a revised (smaller) set of existing assets to be subject to the SPD charge under the simplified SPD and GIT charge options.

- **section two** explains why the new options would not promote allocative efficiency in the manner contemplated by the EA;
- **section three** describes why the options would not have a positive bearing upon new investment approvals and would compromise dynamic efficiency;
- **section four** considers the reasons the EA has offered for charging retailers as opposed to distributors;
- **appendix A** explores the relationship between beneficiaries, costs and prices in competitive and uncompetitive markets; and
- **appendix B** provides a quantitative example of why the EA's proposals are unlikely to materially change the new investment approval process.

38. In several places, this report draws upon material contained in our earlier papers: *Transmission Pricing Methodology – Economic Critique,* February 2013; *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013; *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013; and *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper,* 12 November 2013.

2 Allocative Efficiency

39. The EA contends that all of its revised charging options would promote allocative efficiency by reducing deadweight loss. This is said to be because, under all of its approaches, a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge by "non-beneficiaries" would be paid for by "beneficiaries".[16] In this section we explain the new options may not promote allocative efficiency in the manner contemplated by the EA.

2.1 Private Benefits in Competitive Markets

40. In competitive markets, prices are determined by the interaction of supply and demand. Consumers will demand a product when the private benefit they derive from consuming it exceed the price that must be paid, taking into account other opportunities.[17] Firms will supply a product when the revenue earned from doing so exceeds the costs that must be incurred to produce it, including a return on capital,[18] taking into account the other opportunities.[19] The market price reflects:

- the cost incurred by the "marginal producer" to *supply* the unit of output that "clears the market", i.e., its production costs, including a normal risk-adjusted return on capital; and
- the "willingness to pay" of the "marginal consumer" who *purchases* (demands) the unit of output that clears the market, i.e., the "private benefit" that the consumer derives from the product.

41. This market resource allocation process – most notably the prospect for a demand-side response, coupled with rivalry between different suppliers – can promote short-term static efficiency through:

- enhanced productive efficiency, since firms that face competitive pressure from rivals have an incentive to reduce their costs of production in order to protect or improve their market share; and

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16 *See:* Beneficiaries pay working paper, §7.115(c), 8.32(b)(iii), 9.29(d)(iii); and 10.26(c).

17 The law of demand states that as the price of a product increases consumers will buy less of it (and vice versa). This is because there will be more customers who do not value the product sufficiently highly to pay the higher price.

18 In principle, the return on capital is determined based on the returns that would be earned if resources were diverted to alternative production opportunities in other markets.

19 The law of supply states that as the price of a product increases, more will be supplied. This is because the higher revenue implied by the increased price may justify dedicating more resources to produce a greater quantity of that product. Moreover, because firms generally employ the cheapest available inputs, as output expands, those key ingredients can become scarce and more expensive.

- enhanced allocative efficiency, since:
  - firms facing competition may reduce their prices (possibly as a result of reduced costs), such that previously unmet demand is served at prices that generate positive economic profits, reducing deadweight loss; and
  - firms that are unable to compete effectively will divert their resources to more productive endeavours.

42. The EA places considerable stock in the fact that, in workably competitive markets, consumers pay prices that do not exceed their private benefit, and that this results in static efficiency.[20] However, it must be remembered that, in such markets, the concept of "beneficiary pays" is subsumed into the resource allocation process. The interaction of demand and supply sets the price, with customers deciding whether the value they derive from the service is sufficient to warrant outlaying that sum to purchase it.

43. It is an altogether different matter for a regulator (or a regulated supplier) to *estimate* the value that individual customers derive from a service, and then set prices based on those estimates. Without the forces of demand and supply driving the price – and benefit – discovery process, there can be no presumption that such an approach would promote the types of static efficiency arising in genuinely competitive markets. It might, or it might not. It depends upon a number of factors, including:

   - the **current level of deadweight loss** from unserved demand, which may be modest if demand is highly inelastic;
   - the **accuracy with which private benefits can be identified** – if these are estimated inaccurately it may lead distortions; and
   - whether it causes customers to **change their consumption patterns** so as to reduce the extent to which they are perceived to be beneficiaries.

44. It is quite conceivable that the distortions arising from the second and third factors may be materially worse than those associated with the first. These matters are explored in the following sections. Therein we explain why one cannot rely on the outcomes observed in the wholly different setting of workably competitive markets to support an *assumption* that EA's options would reduce deadweight loss. The effect of that regulated pricing is an *empirical* question and, as we explain below, it is likely to have a *negative* effect on allocative efficiency.

[20] *See:* Beneficiaries pay working paper, §5.3(b).

2.2 Deadweight Loss from Unserved Demand

45. We explained in our report on the EA's CBA working paper that any assessment of the potential for static efficiency improvements must necessarily take into account the level of *inefficiency* associated with the current TPM.[21] As we noted above, in its latest working paper, the EA has suggested that its revised beneficiaries pay options would promote allocative efficiency, since:[22]

> *"[C]harging beneficiaries should reduce deadweight loss, as a greater proportion of the costs of transmission assets that are currently paid for under the interconnection charge by non-beneficiaries would be paid for by beneficiaries."*

46. The manner in which this proposition is expressed is not altogether clear – especially the meaning of "non-beneficiary". After all, if a consumer does not benefit from a service, then it is not clear why she would be buying it. What the passage is *presumably* intended to capture is the notion of inefficiently unserved demand. Specifically, if the current interconnection and HVDC charges are levied in a way that does not reflect consumers' private benefits, in principle, this may result in:

- some parties not consuming the services at all; or
- some parties not consuming as much of the service as they would have at a price that reflected their actual private benefit.

47. In other words, demand that could have been served at prices that generate positive economic profits goes unmet, producing deadweight loss. Any potential reduction in deadweight loss must therefore come from an *increase in demand* from customers who *would not* have benefited from that consumption under the current TPM, but who *would* under the EA's options (and vice versa). Put another way, the only way in which the new approaches can deliver an allocative efficiency improvement is if:

- some customers face *lower* prices than under the current TPM and consequently *increase* their consumption; and
- those customers that face *higher* prices do not inefficiently *reduce* their demand (which depends upon how accurately private benefits are estimated).

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

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21 CEG *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §3.1.

22 *See:* Beneficiaries pay working paper, §7.115(c).

49. All that matters to the assessment of allocative efficiency is the units that the customer would *not* otherwise have consumed, but now does. Only through reducing this previously unserved demand is it possible to "make someone better off, without making someone else equally worse off". This achieves what is known in economics as a "Pareto improvement", which is the defining characteristic of an efficiency improvement as opposed to a bare wealth transfer.

50. This consequently begs the question: to what extent is there likely to be material unserved demand associated with the current TPM? As we explained in some detail our earlier report on the EA's CBA working paper, there may in fact be very little. 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.

51. As we explain in more detail in Appendix A (and in our report on the EA's CBA working paper[23]), 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" that applies the "Ramsey-Boiteux" pricing principle; specifically:[24]

- 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.

52. 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.

53. As Appendix A explains, holding all other things constant, this unit charge serves to maximise demand and the available "consumer surplus". The various other "fixed" charges under the TPM through which Transpower recover the remainder of its revenue requirement then appear to do a reasonably good job of minimising distortions to short-term production and consumption decisions. This is doubtless assisted by the fact that:

- the demand for electricity (the end product for which transmission assets are used to supply) is highly inelastic; and
- the price of transmission makes up only a modest proportion of the price of delivered electricity.

23 *See:* CEG *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §3.1.

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

54. There is, however, some allocative inefficiency associated with the HAMI-based charge, which leads to South Island generators occasionally withholding capacity. It is also conceivable that the interconnection charge may have some effect on the consumption decisions of load at the margin.[25] With those limited exceptions, the use of the existing grid appears be relatively efficient under the current TPM and we would not expect there to be a substantial level of inefficient unserved demand.

55. There may consequently be no material prospect for allocative efficiency gains to be achieved by implementing the EA's options. It is particularly important to avoid conflating the large wealth transfers that would inevitably flow from perceived beneficiaries to perceived non-beneficiaries under the EA's options with genuine efficiency gains. These transfers involve making one party better off at the expense of another and are strictly welfare neutral from an efficiency perspective.

56. Any suggestion that there is an intrinsic benefit from charging private beneficiaries regardless of the effect on unserved demand rests purely upon notions of equity, i.e., that it is "fair" for the beneficiaries of an investment to pay for it. However, the EA's objective is "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers". Its focus must consequently be upon objective efficiency considerations, not subjective notions of fairness.

57. Moreover, even if one were to accept (which we do not) that the EA's options could conceivably give rise to material allocative efficiency gains (as opposed to bare wealth transfers), these would need to be weighed against any offsetting costs. In particular, one would need to consider the distortions to allocative efficiency that would arise from the estimation of benefits as well as the impacts of the options on the consumption patterns of generation and load. We consider these below.

2.3 Estimation of Benefits

58. We observed above that, in a competitive market, the concept of "beneficiary pays" is an inextricable part of the resource allocation process. Customers decide whether the value they derive from a product warrants purchasing it at the market price. If a regulator (or a regulated firm) had perfect information about individual consumers' willingness to pay (which consumers, by definition, have in a competitive market), then it *might* be able to replicate a competitive market outcome.

59. However, in practice, the regulator (or the regulated supplier) will never have perfect knowledge of the private benefits that consumers derive from the service, and will consequently be forced to estimate them if it wishes to introduce a

25 Of course, it must be remembered that some of this demand-side response is a deliberate design feature of the RCPD-based charge in the UNI and USI that is intended to alleviate congestion and arguably does not, therefore, represent *inefficient* unserved demand.

"beneficiaries pay" approach.[26] A key design question is how to produce the most accurate estimate of private benefits. In our opinion, the EA's options exhibit serious shortcomings in this respect.

2.3.1 Inconsistent application of the beneficiaries-pay concept

60. The EA has used the terms "beneficiary" and "private benefit" countless times throughout its consultation process. However, it has not provided clear definitions for either concept. This lack of precision has adverse consequences. Most notably, the absence of any guiding principle about what constitutes a "beneficiary" or a "private benefit" has led the EA to adopt markedly different characterisations of the concepts across its options. For example, as we explain further below:

- the SPD charging approach identifies beneficiaries as those parties that are perceived to have benefited from an asset over the previous 3 years, using daily capping, assumed costs of non-supply and ignoring dis-benefits; and
- the GIT charging options assign 100% of the costs of certain reliability investments to load, based on the contention that they were the principal beneficiaries of those investments when they were approved.

61. These two approaches clearly involve highly inconsistent interpretations of the terms "beneficiary" and "private benefit". This in turn has compromised the manner in which the EA has assessed its "beneficiaries pay" options. Instead of assessing those options based on the accuracy with which they measure private benefits – which is almost impossible to do without a clear articulation of the relevant concept – it has focussed on the *revenue* that each option is likely to raise.

62. Specifically, when weighing up the advantages and disadvantages of options – and of the different approaches to deriving charges within them – those choices that reduce the incidence of the residual charge are viewed most favourably. One of the clearest illustrations of this is the EA's apparent preference for the GIT-based charge over the simplified SPD charge, which is based on its (in our view, misplaced) belief that:[27]

> *"The reduction in deadweight loss would be larger than under the simplified SPD charge option* ***as no residual charges would apply to relevant reliability investments****."* [our emphasis]

63. In other words, the EA assumes that the more revenue that can be recovered through a "beneficiaries-pay" charge (and the less through a residual charge) the

[26] Moreover, the regulator (or the regulated firm) would have to address any incentives that those customers might have in to change their behaviour, or to otherwise alter the extent to which they are perceived to benefit, so as to reduce their charges – a matter we explore below.

[27] Beneficiaries pay working paper, §8.32(b)(iii).

better. In our opinion, that reasoning is deeply flawed. One cannot simply assume that "more is better". What matters is the accuracy with which a beneficiaries-pay option identifies beneficiaries and measures private benefits, and the effect such charges would have on the level of unserved demand.

64. We explain in section 2.3.3 that, under any reasonable definitions, the GIT-based charges do not identify the ex-ante or ex-post beneficiaries of investments, or the causers. They may also result in charges for assets that exceed private benefits. There is consequently no reason to believe that the charges would reduce deadweight loss relative to the status quo in the manner described by the EA in the passage above. Rather, they would compromise both allocative and dynamic efficiency.

65. If a particular beneficiaries-pay charge produces a highly inaccurate estimate of private benefits, the mere fact that it yields a greater proportion of revenue is neither here nor there. It is certainly not a robust basis for preferring it to other charging approaches that deliver less revenue – or to the residual charge itself. To reiterate, what matters is the accuracy with which an option measures private benefits, and its likely effect on the level of unserved demand.

66. As we explain in the following sections, in our opinion, none of the EA's options would accurately capture the extent to which individual parties *actually* benefit from particular assets. This would serve to exacerbate, rather than reduce, the level of unserved demand. The options also entail other problems – including the time profile of the SPD charge – that would lead to additional allocative inefficiency.

2.3.2 Gross benefits under SPD charge

67. The SPD-based charges to be applied to generators and load under the various options are based on an assessment of *historical gross benefits*. Beneficiaries are identified as those parties that are perceived to have benefited from an asset over the previous 3 years, using daily capping, assumed costs of non-supply and ignoring dis-benefits. As is plain from the above description, there are a large number of parameters that comprise each estimate of private benefit.

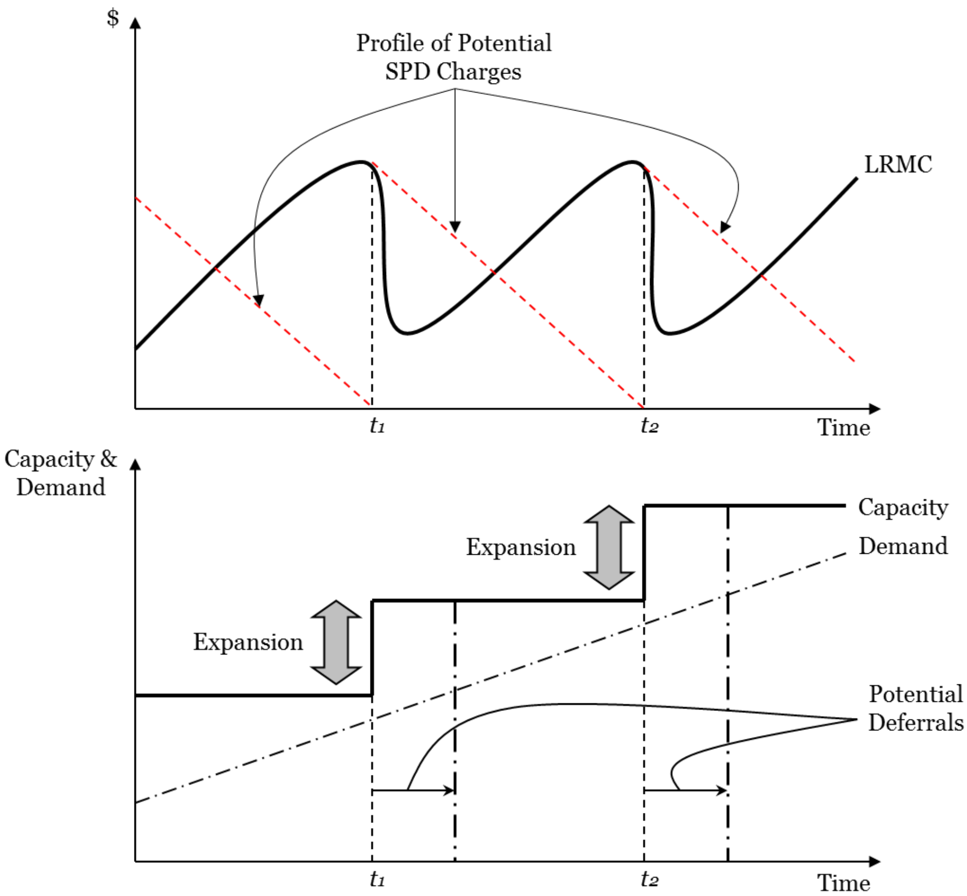
68. We explained in our first report that this would greatly increase the cost of disputes, as parties would continually agitate for those inputs to be changed in ways that favour them. That concern remains valid. However, it is also the case that any errors in any of those parameters (which would be impossible to avoid) would result in an inaccurate estimate of benefits and, potentially, an inefficient reduction in demand – albeit perhaps only at the margin.

69. However, arguably the greatest potential problem with the proposed approach in this respect is the *time profile* of SPD-based charges that may result. In any year, the quantum of the SPD-based charges applied to an asset cannot exceed the revenue that Transpower is permitted to recover for those investments under its

individual price-quality path (IPP). That revenue requirement is based on a return on and of the depreciated regulatory asset values.

70. Transpower is required to apply straight-line deprecation to its asset values under the Commerce Commission's input methodologies (IM). This means that the *potential* total quantum of SPD-based charges is highest immediately after an asset has been built (i.e., when no straight-line depreciation has been applied) and lowest right at the end of its estimated life when the cost-based "cap" has the greatest effect (i.e., when the asset is fully depreciated in Transpower's IPP). Figure 1 illustrates this time profile of potential SPD charges.

Figure 1 Time Profile of Potential SPD Charges



71. Conversely, if there is spare capacity immediately after a transmission asset is built that is reduced over time as demand grows (which is commonplace, given the strong economies of scale associated with transmission investments), the potential private benefits that parties derive from the investment would exhibit the *opposite* pattern. Aggregate private benefits would be relatively low in the years immediately after a new asset is built and would grow over time as demand increases and the previously spare capacity becomes utilised.

72. The charge would therefore result in an *inverse relationship* between the revenue to be recovered through SPD-based prices and both short- and long-run marginal cost, as well as aggregate private benefits. Namely, in the early years of an asset's life the charge would seek to recover the greatest amount of revenue from the fewest number of customers. As the asset ages, the methodology would seek to recover less and less revenue from more and more customers– encouraging them to make even greater use of already capacity-constrained infrastructure. Specifically, the EA's methodology would attempt to recover the most revenue when:

- the forward looking long-run marginal cost (LRMC) is *lowest*, i.e., when there is ample spare capacity and the replacement cost of a new asset is some way off;[28] and
- the aggregate private benefits that parties are deriving from the existing asset are *lowest* because of the significant spare capacity, i.e., demand is low.

And at the costs the SPD charges would attempt to recover would be *lowest* when:[29]

- the forward looking LRMC is *highest*, i.e., when congestion is occurring and the replacement cost of a new asset is imminent; and
- the aggregate private benefits that parties are deriving from the existing asset are *highest – precisely because* the next expansion is looming.

73. This profile of cost recovery is the antithesis of what efficient transmission pricing requires. The most efficient pricing of transmission assets would typically involve lower prices in the *early years* of an asset's life to encourage demand and the highest SPD-based prices *immediately prior to* the new asset being built. The economic logic is that efficient pricing is intended to signal the forward-looking cost of usage to consumers so that those who do no value the service sufficiently can alter their behaviour and the costs can be avoided or deferred.

74. The appropriate time at which to send these signals about the cost of incremental usage is *before* fixed and sunk costs are incurred. In the years immediately following a new investment, the short- and long-run marginal cost of additional demand is "low", since the cost of the next expansion is modest in NPV terms.[30] This

28 In the time period immediately following a capacity replacement/expansion (i.e., those following t_1 and t_2 in Figure 1) the forward-looking cost of the next increment to capacity is low, because the value of any potential deferral of that future capacity requirement is relatively low due to the effect of discounting. As spare capacity declines over time and the need to invest in new capacity approaches (i.e., the time periods leading up to t_1 and t_2), the present value of the cost of the next increment to capacity increases, because the value created through any potential deferral is closer in time and so less (negatively) affected by discounting.

29 This would be exacerbated by the daily cap which would restrict the revenue the SPD charges could recover during peak usage periods, i.e., the periods that are driving the cost of the transmission grid.

30 This is because the cost of bringing forward by, say, one year, an investment that would otherwise have taken place in 50 years is relatively modest in NPV terms compared to the cost of bringing forward to today the cost of an investment that would otherwise have taken place in 2 years.

means that prices should be "low" all things being equal. Conversely, when a new expansion is imminent, the short- and long-run marginal cost of additional demand is very high indeed,[31] prices should be "high" to signal those costs.

75. The proposed SPD charge would consequently not necessarily reflect either private benefits or forward-looking costs and would provide highly inefficient price signals to grid users. It would mean that there are customers that choose to use a transmission asset at an SPD-price based on its depreciated historic cost, who would not demand as much of the service if the charge was based on the forward-looking replacement cost of a new asset. More specifically, there may be customers who are estimated to have a private benefit that is:

- greater than the share of the annual revenue requirement that they must pay (assuming that aggregate private benefits exceed that annual requirement); but
- less than or equal what they would have to pay if total SPD-charges were capped based on the forward-looking replacement cost of a new asset.

76. This would distort consumption patterns and compromise allocative efficiency, since some consumers would be procuring transmission services when the private benefits they derive from that demand is less than the forward-looking cost of meeting it. This would not occur in a workably competitive market. Moreover, as we explain in more detail in subsequent sections, the time-profile of SPD charges can also be expected to give rise to undesirable incentives when it comes to the process for approving new investments, which may also harm dynamic efficiency.

2.3.3 Benefits under the GIT-based charge

77. The definition of "beneficiaries" that is applied to various reliability investments under the GIT-plus-SPD and SPD-plus-GIT options is altogether different to that described above. Under these options, the costs of the relevant reliability investments are assigned to load. This is based on the contention that load were considered to be the principal beneficiaries of reliability investments at the time they were approved. The EA explains that:[32]

> *"The rationale for this is that the charge would be applied to those who receive the benefit that was the principal justification for the investment. This is because the intention with the GIT-based charge is to ensure that incentives to promote an investment are aligned with willingness to pay for it. This should help promote efficient investment.*
>
> *For example, the primary justification for the NIGU project was improved reliability in the upper North Island region; if the project did not promote*

31 *Ibid.*

32 Beneficiaries pay working paper, §8.12-8.13.

> *this objective it would not have proceeded. The NIGU project was also justified by Transpower on the basis that it would reduce the risk of cascade failure affecting the Waikato and Bay of Plenty. However, the project would not have proceeded for that reason alone, as the benefits of reducing the risk of cascade failure were insufficient by themselves to justify the investment. Accordingly, for the NIGU project the GIT-based charge would only be applied to loads in the upper half of the North Island."*

78. If one of the principal motivations for introducing the EA's options is to promote static efficiency by reducing unserved demand, it is difficult to grasp the rationale for this difference in approach between reliability and other investments. Under section III of the *Electricity Governance Rules*, a reliability investment would be approved if it was necessary to meet applicable grid reliability standards and maximised the expected net benefit compared with alternative projects, with the proviso that the expected net benefit *could be negative*.

79. The effect of the proviso is that the cost of a reliability investment might well exceed the expected net benefit (unlike for an "economic investment"). Assigning the cost of reliability investments to load might therefore result in them paying charges that exceed their private benefit. This is made even more likely by the fact that load in a particular location will never be the only "private beneficiaries" of reliability investments, for example:

    - generators in certain locations would, by definition, also benefit, since some would receive higher prices than would otherwise be the case; and
    - load in locations outside the charging area may also benefit, e.g., the EA acknowledges in the passage above that customers in the Waikato and the Bay of Plenty will benefit from the NIGU project.

80. It is therefore not obvious why the GIT-based charging options would improve upon the status quo. Indeed, if the EA's apparent belief that the current TPM leads to a material level of unmet demand is correct (which is far from clear), then it follows that this aspect of the GIT-based approaches may do so as well. Specifically, customers may reduce their use of "reliability investments" in precisely the same way, resulting in unserved demand and deadweight loss.

81. It is also worth noting that while the EA characterises its approach as a "beneficiaries pay" approach, its focus on "the principal justification for the investment" bears some resemblance to a *causers pay* approach. The EA seems to be trying to identify the parties who caused the need for an investment, i.e., the parties without whom an investment would not have proceeded. However, its methodology results in it identifying *neither the beneficiaries nor the causers*.

82. Perhaps the most obvious example of this is load based in the far north. Few would argue that these customers *caused* the need for reliability upgrades such as NIGU. Rather, it is widely regarded as being strong growth in the Auckland region that

precipitated the need for the investments. Nonetheless, under the EA's approach, those customers in the far north are lumped in with Auckland-based load, since they "receive the benefit that was the principal justification for the investment".

83. The upshot is that the GIT-based charging options do not accurately identify the ex-ante beneficiaries, the causers or the ex-post beneficiaries. This charge therefore gives rise to precisely the same potential for unserved demand that is thought by the EA to be problematic with the existing TPM. It is therefore not obvious why it is to be preferred. Moreover, as we explain in more detail below, it gives rise to poor incentives when it comes to the process for approving new investments.

2.4 Effect on Consumption

84. If market participants are aware of the methodology that will be used to assess the extent of their private benefits they will have an incentive to change their behaviour in ways that reduces the extent to which they are perceived to benefit. As we have highlighted in our previous reports, the arena in which these changes in behaviour is most likely to be observed is the wholesale market, in which generators may be enticed to change their bidding behaviour in inefficient ways.

85. Currently, generators' expected transmission charges have little, if any bearing on their wholesale bids.[33] However, if any of the EA's proposals is implemented, generators would know that their annual transmission bill will depend – in part – upon the difference between its wholesale bids and the market price. Figure 2 below provides a simple example. With the transmission asset in place, Generator A bids its short run marginal cost (SRMC) and is dispatched, but once it is removed, it cannot access the node.

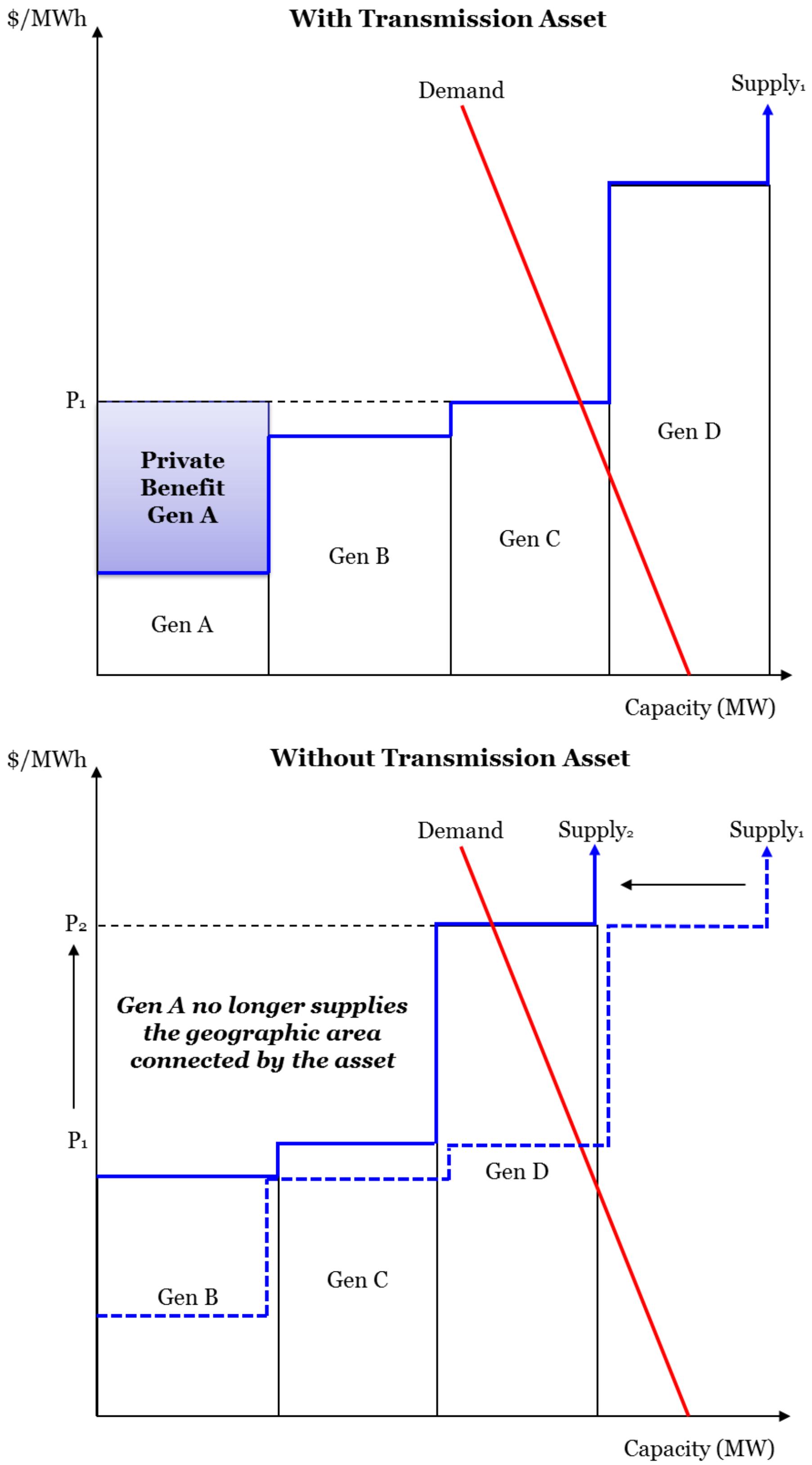
86. In this example, Gen A would be estimated by the SPD model to have received a private benefit equal to the difference between its SRMC-based bid and the market clearing price (P_1). This would form the basis for its transmission charge for that time period. It is not hard to imagine that Gen A might therefore seek to reduce the extent to which it is perceived to benefit from the asset by increasing its bid above its SRMC – something that it would have no incentive to do under the current TPM.

87. In doing so, Gen A would seek to optimise the trade-off between lowering transmission charges (by bidding above SRMC) and increasing the probability of not being dispatched, with the attendant negative effects on its profitability.[34] If this type of behaviour became widespread it would have the potential to seriously compromise the efficiency of a wholesale market that is widely acknowledged as being at the forefront of international best practice.

33 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.

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

Figure 2 Estimation of Private Benefit



88. As soon as generator's have an incentive to lodge bids that do not represent their "true" SRMC there is the potential for them to be dispatched out of "true merit order". We have explained in our previous reports how this can seriously compromise static and dynamic efficiency by leading to unnecessarily higher cost generation and higher prices for consumers. In our opinion, the EA's revised options have not addressed this potential problem.

89. It is worth noting the clear parallels there are here with the well-recognised inefficiencies that would arise if the wholesale prices that generators were paid were to be based on their bids (a "pay-as-offered" approach) as opposed to the highest offer required to satisfy demand. In his paper entitled *The Economics of Electricity*, the Chairman of the EA, Dr Brent Layton, provides a concise and compelling explanation of the effect that such an approach would have on generator bidding conduct. That explanation is reproduced in full below:[35]

> *"...it is easy to see that if the Code was changed in this way generators would quickly adjust the way they set their offers. In order to maximise their returns they would estimate the highest price needed to fully satisfy demand and, if they are happy to be dispatched at that price because it is above their actual marginal cost, they would pitch their offer at just below that price.*
>
> *If a generator over-estimates what the market clearing price will be, it will not be dispatched. If the generator has lower marginal cost than another one that offered at a lower price and was dispatched, there will have been out-of-merit dispatch. In other words, a pay-as-offered market will result in higher cost generation operating than is necessary, which will be a cost to society. Consumers will ultimately bear this cost and so a pay-as-offered arrangement is detrimental to the long-term benefit of consumers.*
>
> *Moreover, since under a pay-as-offered Code, generators will try to offer at just under what they estimate the market clearing price will be, provided this is above their actual marginal cost, the outcome would be that the supply schedule would not fall away to zero as volume falls as it does under the current Code. As a result, any unexpected fall in demand will result in a higher price for consumers (and generators) than would be the case under the current Code. The current Code encourages generators to offer at their actual marginal cost, no matter how low that is, and this benefits consumers."*

90. This critique could also be applied – verbatim – to the EA's proposed SPD charge, which would *also* result in generators' compensation being based on their wholesale bids – in this case through the effect on their transmission charges. The charge is therefore an "indirect" form of pay-as-offered pricing. It follows that it can be expected to give rise to *exactly the same distortions* that Dr Layton cautions against

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35 Layton, B., (2013) *The Economics of Electricity*, 4 June 2013, §8-10.

in his paper, and which we described above, i.e., bids above SRMC, out-of-merit dispatch, higher cost generation than is necessary and higher costs for society. The EA's promotion of the SPD method but rejection of "pay-as-offered" approaches is consequently difficult to reconcile.

91. Finally, it should be recognised that, even if no inefficient dispatch resulted from generators altering their bidding (i.e., they never raised their bids by enough to not be dispatched when price exceeded SRMC) the altered bidding would still compromise the estimate of benefits under the Authority's model. For example, imagine generators can predict perfectly what the market price will be at all times. Then those generators with SRMC below this would rationally bid just under the market price, resulting in generators as a whole being estimated to have zero (or very low) benefits.[36]

2.5 Summary

92. The EA contends that all of its revised charging options would promote allocative efficiency by reducing deadweight loss – presumably that arising from unserved demand under the current TPM. In our opinion, its options would not have such an effect. First, the use of the existing grid appears be relatively efficient under the current TPM, which essentially results in a relatively efficient two-part tariff – and we would not expect there to be a significant level of inefficient unserved demand.

93. There is therefore no material prospect for allocative efficiency gains to be achieved by implementing the EA's options – the large welfare neutral transfers that they would inevitably entail should not be confused as such. Moreover, even if material gains were thought to be achievable (which we do not consider to be the case), these must be weighed against the distortions to allocative efficiency that would arise from the implementing the SPD methodology, including:

36 The only time a generator would be estimated to benefit from an asset would be if the existence of that asset raised the price that they received above their bid price. However, the price that a generator actually receives with all assets in place is the market price. If the bid price is infinitesimally below the market price then they earn zero profits with all assets in place. Hypothetically removing an asset can produce only two outcomes. The first is an increase in the price that the generator would have received, which would make them a loser as a result of the asset in question being in place. The alternative is a reduction in the price that the generator would have received – in which case the generator would hypothetically not have been dispatched, making it a winner from the asset being in place. However, because the difference between the bid price and market price with the asset in placed is infinitesimal, the benefit attributed to the generator is similarly trivial. The exception, of course, is if the generator makes an error in its estimation of the market price, i.e., if it overestimates the price and is not dispatched in the "factual", or if it underestimates the price (perhaps deliberately, i.e., erring on the side of underestimating rather than overestimating in order to reduce the chance of not being dispatched – perhaps by bidding, say, 5c below the expected market price rather than, say, 1c) and is estimated to have derived a small benefit. However, the same general principle applies.

- the inaccuracies inevitably associated with assumptions that must be made about the cost of non-supply and the capping period under the SPD charge, all of which would lead to private benefits being over- or under-estimated;
- the inefficient time-profile of SPD charges, which would result in prices being lowest at the end of an asset's life and provide no signal of forward-looking costs – the exact opposite of what efficient transmission pricing requires; and
- the inability of the GIT-based charging options to accurately identify the ex-ante or ex-post beneficiaries, or the causers of reliability investments, which may lead to the same inefficiencies said to be associated with the current TPM.

94. Moreover, market participants may have an incentive to change their behaviour in ways that reduce the extent to which they are perceived to benefit from assets, which would further compromise efficiency. Most notably, profit maximising generators would seek to reduce the extent to which they are perceived to benefit from transmission assets by increasing their bids above SRMC. If this conduct was widespread then, at best, it would distort the estimate of benefits under the Authority's model. At worst, it would seriously compromise the efficiency of the wholesale market by leading to out-of-merit dispatch, higher cost generation than is necessary and higher costs for society.

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3 Dynamic Efficiency

95. The EA contends that all of its revised SPD charging options would promote dynamic efficiency by increasing the transparency of the benefits that parties obtain from transmission assets. The EA claims that this would place stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process, and lead to more efficient investment outcomes.[37] In this section we explain why the options are, in fact, unlikely to have any beneficial impact upon the new investment approvals or on dynamic efficiency.

3.1 No Material Assistance to the Commission

96. 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 (Commission). To meet that test, a proposed investment must, amongst other things, have the highest "expected net electricity market benefit".[38] 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 for economic investments.

97. The EA's options are targeted at the *process* by which that Investment Test is undertaken. It believes that if parties must pay directly for the investments from which they benefit, they would have a greater incentive to participate in the process. More specifically, the EA presumably considers that this would produce *superior information* than is the case under the current TPM, which would make it easier to identify those investments that will maximise the net present value of market benefits ("good" investments) and those that will not ("bad" investments).

98. The EA must therefore believe that the Commission is currently being prevented from making optimal investment approval decisions by an asymmetry of information. That is, it must consider that market participants have a superior understanding of those investments which are efficient and those which are not, but that they are not sharing that information effectively with the Commission. The EA believes that charging perceived beneficiaries would address that problem by providing them with a greater incentive to participate in the investment process.

99. In other words, the EA claims that parties that were previously disinclined to participate in new investment processes, or were participating in unconstructive

37 *See:* Beneficiaries pay working paper, §7.115(a); §8.32(a), (b)(i) and (ii); §9.29(a), (b), (d)(i) and (ii); and §10.26(a).

38 Commerce Commission, *Re Transpower Capital Expenditure Input Methodology Determination* [2012] NZCC 2, 31 January 2012, Schedule D1, p.53.

ways would, under its new options, have an incentive to engage – and to provide the Commission with the information it needs to judge good investments from bad. This would therefore overcome the asymmetric problem that has supposedly been hindering the Commission hitherto and lead to better investment outcomes.

100. In our opinion, that belief is misplaced. First, as we explained in our first report,[39] the EA is yet to provide any material to suggest that the Commission's IM has not facilitated efficient investment outcomes – or that it is incapable of doing so in the future without the proposed TPM reforms. In other words, the EA has not established that there is a problem with the Commission's new investment framework that needs to be solved.

101. Second, even if there was a problem arising from asymmetric information, the EA's transmission pricing options would not address it. To see why, it is instructive to consider how a new investment approval process might proceed under the current TPM and under the EA's new options. Suppose, for example, that the HVDC link did not exist[40] and that Transpower was proposing to build it as an "economic investment". Under the current TPM:

- the net beneficiaries – South Island generation and North Island load – would want it to be built and lobby for it, but South Island generators would almost certainly also point out that they would not be the only beneficiaries of the link and that they should not be required to pay for 100% of the investment;[41] and
- the parties that would be harmed by the investment – North Island generation and South Island load – would not want the link to be built and would presumably lodge submissions opposing it, despite the fact that they would not have to directly pay for it.

102. How then, would the process change under the EA's options? In our opinion, the best case scenario is that in which the process remains largely unchanged (we discuss some of the more specific potential distortions that might arise in the following section). If parties were going to be required to pay for the link based on their estimated gross private benefits, then:

- the net beneficiaries – South Island generation and North Island load – would want it to be built and lobby for it, but they would not want to pay a price equal to their gross benefit, e.g., they might say: "we will benefit overall, but not on the days the link flows south, and so our charges should be reduced"; and
- the parties that would be harmed – North Island generation and South Island load – would not want the link built and would lobby against it and they might

[39] CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, §3.1.

[40] That is, there were two geographically separate transmission grids.

[41] Indeed, South Island generators have made precisely this point on numerous occasions.

also say: "if it is built despite our wishes, we will benefit on the days it flows south but will be harmed overall, so we should not have to pay anything".

103. In other words, both processes would yield a range of submissions – some in favour of the link and some opposed to it. Moreover, in both processes, submissions would be motivated in every case by the effect of wealth transfers, not efficiency gains. The only way that the TPM can give rise to a situation where stakeholders only strongly advocate NPV positive projects is when it turns a potential Pareto improvement into an actual Pareto improvement.

104. In non-technical terms, this requires the beneficiaries of a new investment to pay not just the costs of the "good" investment, but also fully compensate the losers. It is only in this way that the investment would make some parties better off (the net beneficiaries) without making anyone else worse off (since the parties that would otherwise be harmed are fully compensated). Only then would the TPM "reveal the answer", obviating the need for the Commission to exercise its judgement.

105. In the above example, the TPM would have to require the net beneficiaries of the HVDC link – South Island generation and North Island load – to pay not only for the asset itself, but also for the losses incurred by North Island generation and South Island load. Unless the "losers" are compensated in this fashion, there would still be a cacophony of competing voices, some in favour of the link and some opposed. Appendix B provides a more comprehensive numerical example.

106. However, in order for the TPM to allocate the losses imposed on third parties there is the obvious practical difficulty of arriving at an accurate estimate of benefits and costs (a matter that we discussed – albeit in relation only to benefits – in section 2.3). Putting aside those practical difficulties, there is also the problem that the amount of money that would need to cycle through the TPM might then need to be much greater than Transpower's actual revenue requirement. It is no doubt for this reason that the EA has not proposed such an approach.

107. Note that it is even more difficult to achieve such an outcome in respect of "bad" investments, i.e., to manufacture a universal voice opposed to such investments. This would require the potential losers from an investment to pay the potential beneficiaries not to support it. There is no obvious regulatory mechanism to achieve this outcome. It would therefore presumably have to be done through side-payments, which would be highly unusual and impractical.

108. However, without these forms of compensation, there is unlikely to ever be a universal chorus supporting a "good" investment or opposing a "bad" investment. Implementing a beneficiaries pay option would therefore not solve the problem of deciding what to build and when. The Commission would still have to consider a range of conflicting submissions motivated by wealth transfers and, ultimately, make a judgement about the efficiency of an investment. That judgement would be made by reference to the market benefits test set out in the IM – as it is currently.

109. For that reason, we see no basis for the EA's belief that its options would overcome any problems arising from asymmetric information (to the extent they were material) and lead to superior investment outcomes. At best, they would have no effect on future investments – the Commission would still have to consider the same mix of conflicting submissions, all motivated by wealth transfers. However, as we explain in more detail below, the options may make matters worse by giving parties greater incentives to oppose beneficial investments and/or to lobby for less beneficial investments for strategic reasons.

3.2 Potential Distortions from the Time Profile of Charges

110. In sections 2.3.1 and 2.3.2 we foreshadowed that the designation of beneficiaries under the GIT-based charges and the time profile of the SPD-based charge risked giving rise to dynamic (as well as to allocative) inefficiencies. Because the GIT-based charging options would not accurately identify the ex-ante beneficiaries, the causers or the ex-post beneficiaries of an investment, this might lead to situations where load is required to pay charges that exceed their private benefits.

111. In addition to the static inefficiencies that this would entail, it can also be expected to prompt stern opposition from those parties when such an investment is proposed. That opposition might not exist to the same extent – or even at all – under the current TPM, under which the costs of reliability investments are spread more diffusely across load. In other words, the GIT-based charging options may serve to push more parties into the camp voicing opposition to "good" investments.

112. The time profile of SPD-based charges may also give rise to undesirable incentives when it comes to the process for approving new investments. We explained above how the use of straight-line depreciation under Transpower's IPP would produce a time-profile of cost-recovery whereby the potential ("capped") SPD-based charges decrease steadily over the asset's life. When deciding whether to support a good investment, a party would therefore naturally ask:

- will I benefit from this investment?; *and*
- will I benefit *even more* from a *different* investment, such as:
  - a smaller investment that entailed lower costs?; and/or
  - an investment that took place at a later date when demand is higher?

113. If the answer to either of the questions in the second bullet is "yes", then beneficiaries may oppose a "good" investment, simply because they personally would benefit more from another option that offers fewer overall market benefits. The design of the SPD-based charge – including its time profile – makes this outcome highly likely. For example, suppose that Transpower is proposing to build a new asset that will be subject to the SPD-charge (not a GIT charge).

114. Suppose also that, because of the significant economies of scale associated with transmission infrastructure, the asset would eliminate congestion for some time and create significant spare capacity – as is commonly the case.[42] Given the way in which the SPD-based charge is designed, it is conceivable that, in the years immediately following its construction, the aggregate private gross benefits would not be sufficient to recover Transpower's annual revenue requirement for the asset.

115. In other words, during this initial period, the SPD-based charge would seek to recover from private beneficiaries 100% of their gross private benefits, leaving them indifferent as to whether the asset is there.[43] However, as Transpower's annual revenue requirement for the asset declines (due to the aggregate effect of straight-line depreciation on the annual revenue requirement – i.e., the "cap") and as demand grows (as previously spare capacity is utilised), then:

- the total SPD-based charges to be recovered (the "cap") from all private beneficiaries in any year decreases; and
- the total quantum of private benefits from the asset in any year starts to increase due to the increase in demand.

116. In time, an inflection point would be reached where aggregate private benefits start to exceed the "cap" derived from the depreciated asset value. Put another way, the total annual private benefits would exceed the annual revenue allowance and the cap would cease to bind. From that point forward, a greater number of private beneficiaries would start to pay for a "smaller slice of a smaller pie". They would also no longer be indifferent towards the asset, since the TPM would not be removing[44] 100% of the private benefits that they derive from it.

117. It follows that parties may have an incentive to lobby for investments for which this inflection point *would come sooner*. Even if a party would be a private beneficiary of, say, a proposed $100m investment that would maximise overall market benefits, it may still have an incentive to lobby for something else. The party might suggest that, say, a $75m investment proceeds instead and potentially at a later date – both of which might net it greater private benefits (net of transmission charges), given the design of the SPD charge.

118. In other words, like the GIT-based charging options described above, the SPD-based charge may serve to push *even more* parties into the camp opposing "good" investments – *including* the *net beneficiaries*. The reason for this is that those net

[42] Once the land has been purchased and the towers built, there is not much difference in cost between a low capacity line and a high capacity line. Because it is not practicable to build transmission lines in increments of 1MW, in most instances high capacity lines are constructed. Because lines tend to be large and infrequently built, once they are built they tend to eliminate congestion.

[43] Of course, as section 2.3.1 explained, it is unlikely to achieve this with precision given the inaccuracies inevitably associated with the estimate of benefits, which can lead to the inefficiencies discussed earlier.

[44] Or at least attempting to remove – see previous footnote.

beneficiaries would not be asking themselves: "is this investment the best outcome for the market?" They would be asking: "is this investment outcome the best outcome for me, or could my benefits be even higher if something else was built?"

119. The participants in the investment process would not be motivated by what is best for the market. Profit-driven enterprise would, quite understandably, want the outcome that delivers the most benefits to them. Implementing the EA's options in an attempt to charge beneficiaries would therefore not cause them to start lending their unequivocal support to "good" investments if they could earn even higher individual private benefits if a less efficient investment proceeded.

120. It would consequently be left to the Commission to determine whether an investment should proceed, based on its assessment of what is best for the market. Throughout its consultation process, the EA has not provided any compelling reasons why its options would make this process any easier or lead to superior investment outcomes. For the reasons described above, the EA's options may actually make the Commission's task more difficult and risk inefficient outcomes.

121. Potentially even more problematically, if the increased opposition to "good" investments led to Transpower being made to delay expenditure and/or building smaller assets, there is a risk that the EA might view this as evidence of its reform working. Specifically, it might surmise that the "stronger incentives" that it had created for beneficiaries to participate in the investment process had revealed that Transpower was proposing to build things "too big and too early".

122. It might consequently conclude that its revised pricing methodology had prevented those inefficient investments from proceeding, giving rise to substantial dynamic efficiency gains. However, the reality may be quite different. For the reasons described above, the EA's reforms may have instead given parties stronger incentives to advocate against efficient investments, leading to the wrong things being built at the wrong time and substantial dynamic efficiency *losses*.

3.3 Summary

123. Throughout its consultation process the EA has reiterated its belief that its beneficiaries-pay options would enhance dynamic efficiency. It contends that those approaches would place stronger incentives on parties identified as beneficiaries to participate in the investment decision-making and approval process, and lead to more efficient investment outcomes. In our opinion, the EA is yet to provide a reasonable foundation for this proposition.

124. Under both the current TPM and the EA's options there would be a range of submissions in response to a new investment – some in favour and some opposed. Those submissions would be motivated in almost every case by the effect of wealth transfers, not efficiency gains. The only way that the TPM can give rise to a situation

where stakeholders only strongly advocate for and against the appropriate projects is when an *actual Pareto improvement* is realised. This means that:

- for NPV positive investments, the beneficiaries would need to pay not only for the project, but also fully compensate the losers to stop them opposing it; and
- for NPV negative investments, the potential losers would need to pay the potential beneficiaries to stop them from supporting it.

125. Putting aside the obvious practical estimation difficulties, the amount of money that would need to cycle through the TPM to achieve the former might need to be much greater than Transpower's actual revenue requirement. Moreover, there is no obvious regulatory mechanism to achieve the latter – achieving a universal voice of opposition would instead require side-payments. However, without these forms of compensation (which the EA is not proposing):

- there would never be a unanimous opinion amongst submitters – there would always be a range of submissions for and against every investment;
- submissions would not be motivated by what is best for the market – profit-driven firms will want the outcome most benefits *them;* and
- the TPM therefore cannot "reveal" the efficient outcome – the Commission must make that judgement using the criterion in its input methodology.

126. For that reason, there is no basis for the EA's belief that its options would overcome any problems arising from asymmetric information and lead to superior investment outcomes. At best, they would have no effect on future investments – the Commission would still have to consider the same mix of conflicting submissions, all motivated by wealth transfers. However, the EA's options may make those processes *less effective* by providing parties with stronger incentives to oppose efficient investments and/or to lobby for less efficient investments for strategic reasons. For example:

- by assigning the costs of certain reliability investments to parties that are neither the sole ex-ante beneficiaries, the causers nor the ex-post beneficiaries, this may cause them to oppose those investments, even if they are efficient; and
- the design of the SPD-based charge is likely to result in beneficiaries agitating for smaller investments and/or for investments to be delayed, so as to increase their individual private benefits – even if overall net market benefits are lower.

127. If this increased opposition led to Transpower being made to delay expenditure and/or building smaller assets, there is a risk that the EA might view this as evidence of its reform *working*. It might surmise that the "stronger incentives" that it had created for beneficiaries to participate in the investment process had revealed that Transpower was proposing to build things "too big and too early". However, the reforms may instead have caused parties to advocate against efficient investments, leading to the wrong investments being made at the wrong time.

4 Charge Retailers or Distributors?

128. The EA preliminarily concludes that it would be better to make retailers subject to the SPD charge rather than distributors. The principal advantages are said to be their "greater familiarity with wholesale market" and their "greater incentive to scrutinise transmission costs because of the lack of a mandated ability to pass through transmission charges."[45] In our opinion, these do not constitute sound reasons for favouring retailers over distributors.

4.1 Participation in Pricing and Investment Processes

129. At the TPM beneficiaries-pay working paper discussion forum on 29 January 2014, the EA provided the analogy of airports and their airline customers to support its conclusion that it was preferable to charge retailers.[46] Specifically, it pointed to the extensive consultations that take place between airports and airlines – including in relation to new investments. This was said to be desirable and analogous to the situation that would emerge if Transpower charged retailers directly.

130. In our opinion, this is neither a helpful nor relevant analogy for the simple reason that it features no equivalent to a distribution company. A potentially more instructive analogy is to imagine what difference it might make if there *was* an intermediate party that sat between the airport and the airlines. For example, imagine that the airport levied charges on a hypothetical "distributor" who then passed them on to airlines. Imagine also that:

- the "distributor" did not scrutinise the charges at all – it was able to simply pass them through to the airlines, i.e., it had a "mandated ability" to do so;
- the airlines had a "greater familiarity" with how the charges had been derived than the "distributor"; and
- the airlines were still able to participate in pricing consultations, i.e., they could still make their views known to the airport.

131. Would levying charges on the hypothetical "distributor" instead of airlines make any difference in these circumstances to pricing and investment outcomes? In our opinion, almost certainly not. The fact that airport charges are "passed through" by an intermediate party would not diminish airlines' incentives to participate in those processes. If they knew that they were ultimately going to have to pay those charges – albeit indirectly – they would have incentives to scrutinise them.

45 Beneficiaries pay working paper, §7.126.

46 *See also:* Beneficiaries pay working paper, §7.124(b).

132. Electricity retailers are no different. Even if they do have a greater familiarity with wholesale market and a greater incentive to scrutinise transmission costs (matters we consider below), charging them directly should have no noticeable effect on charging and investment outcomes. Just like the airlines in the above example, retailers' incentives to scrutinise transmission costs do not diminish if they pay indirectly – all that matters is that they pay.

133. A cursory inspection of the Electricity Commission's archived website reveals that generators (and distributors) were vocal participants in every major grid investment consultation that was undertaken from 2005 and 2007.[47] In other words, retailers have been scrutinising transmission proposals for many years despite the fact that they do not directly pay transmission charges to Transpower. We see no reason why that would change if distributors continued to be charged.

4.2 Incentives of Distributors vs. Retailers

134. The EA may also have overstated the difference between retailers' and distributors' incentives to scrutinise transmission costs. The fact that distributors have a "mandated ability" to pass through transmission charges has not prevented them from participating in many of the grid investment consultations described above. They have also been active participants throughout the EA's current consultation process, despite transmission charges being a pass-through cost.[48]

135. Furthermore, despite not having a "mandated ability" to pass-through transmission charges, retailers are nonetheless going to be in a position to do so because of the competitive dynamics of the retail market. If the retail market was hypothetically perfectly competitive then, by definition, 100% of any transmission charges would be immediately passed through to end customers. If they were not, then a retailer would not recover its costs and would exit the market.

136. In the more realistic setting of a workably competitive market – which the retail market is more likely to resemble – there may be practical impediments that prevent instantaneous pass-through of transmission charges. These include factors such as contracts that may fix prices for a period. However, once the effect of any such constraints diminishes, any SPD or residual charges that retailers faced at a particular node can be expected to be passed through to retail prices.

137. Moreover, there is no obvious reason to think that the different retailers at a node would face materially different SPD and residual charges. The effect on each retailer

47 *See:* http://www.ea.govt.nz/our-work/consultations/grid-investment/

48 For example, there were 11 submissions from distributors (or groups representing distributors) in response to the EA's first issues paper. These were almost universally opposed to the basic premise of the EA's proposal, despite the fact that transmission charges are a pass-through cost. *See:* Electricity Authority, *Summary of submissions, Transmission Pricing Methodology: issues and proposal consultation paper*, 28 May 2013, p.18.

can be expected to be uniform, on average, which would also serve to facilitate 100% pass-through of transmission costs. The EA acknowledged in much in its first issues paper when commenting upon the effect of levying the residual charge on retailers:[49]

> *"Since all retailers operating at a node would face the same charge they would face the same costs and therefore have an ability to pass the charge onto consumers."*

138. This means there is unlikely to be a material direct benefit to retailers from lower charges or a material cost from higher charges. In either case, the retailers at the affected node can be expected to pass through 100% of any change to customers. The EA again acknowledges this in its beneficiaries pay working paper.[50] It also notes that distributors are more likely to directly pass through transmission charges to large consumers, which would preserve price signals to those parties.[51]

139. For those reasons, it is not at all clear that retailers would have a "greater incentive to scrutinise transmission costs because of the lack of a mandated ability to pass through transmission charges". As the EA itself concedes, if competition is effective and all retailers at a node face the same costs, then they are likely to pass through 100% of transmission charges. The incentives of retailers and distributors to scrutinise transmission costs would therefore not be materially affected.

4.3 Familiarity with the Wholesale Market

140. In its original proposal, the EA – and a number of submitters – cited the greater familiarity that retailers have with the wholesale market as a key reason to levy transmission charges upon them directly. Distributors were said to have less understanding of the half-hourly workings of the spot market and were therefore not as well placed to manage the SPD charge.

141. In addition, the volatility and uncertainty about SPD charges (given ex-post application that was initially proposed) was seen as unworkable for distributors operating under their default price-quality paths (DPPs). In our opinion, these reasons would have had some merit if the EA were intending to proceed with its original proposal. However, the changes that have been made render them moot.

142. Amongst the various changes that the EA has made to its original SPD charge design in its latest working paper are a move to ex-ante as opposed to ex-post charges, and the adoption of the three-year moving average. These two alterations will mean that

49 Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012, §5.6.76.

50 Beneficiaries pay working paper, §7.124(b).

51 Beneficiaries pay working paper, §7.122(e).

distributors know the SPD charges that they will face for the coming year (due to the ex-ante application) and will have a much better idea of the prices that they will face beyond that horizon (due to the three year moving average).

143. It can therefore no longer reasonably be said that "familiarity with the wholesale market" is a relevant criterion upon which to judge the merits of charging distributors or retailers (if indeed it ever was). Under any of the EA's revised options, any comparative disadvantage that distributors have in terms of the half-hourly workings of the wholesale market would be of considerably less relevance to their ability to manage the SPD charge.

144. The fact that distributors would be better placed to forecast transmission charges with reasonable accuracy under the EA's revised options also ameliorates concerns about the interaction between SPD charges and their DPPs. In any event, in our opinion, if distributors *still* would not be able to arrive at reasonable forecasts, the appropriate response is not to change the party who is charged, but to improve the predictability of the methodology itself.

4.4 Potential Costs

145. Hitherto we have explained why the decision to charge either distributors or retailers should have no noticeable effect on either party's incentive to scrutinise or pass-through transmission costs. These supposed advantages therefore do not constitute sound reasons for which to charge retailers as opposed to distributors. However, it is potentially relevant to consider the transaction costs that would be involved with each alternative.

146. In this respect, there would appear to be some clear advantages to charging distribution businesses instead of retailers. For example, the EA observes that distribution companies[52] are already, and will continue to be, transmission customers by virtue of their connection to the transmission network. If Transpower was required to charge retailers directly, it would be forced to enter into a series of new contracts with those parties for the use of the transmission system.

147. Charging retailers is therefore likely to entail material additional transaction costs in terms of establishing use-of-system agreements, relative to the scenario in which it continued to charge distributors. Moreover, as we noted in our first report, the EA's proposal would heighten risks for retailers – disproportionately so for smaller retailers without "natural hedges".[53] Charging retailers is therefore likely to entail additional costs for no obvious benefits.

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52 Beneficiaries pay working paper, §7.122(a).

53 CEG, *Transmission Pricing Methodology – Economic Critique,* February 2013, §5.2.

4.5 Summary

2. The EA preliminarily concludes that it would be better to make retailers subject to the SPD charge rather than distributors. The principal advantages are said to be their "greater familiarity with wholesale market" and their "greater incentive to scrutinise transmission costs because of the lack of a mandated ability to pass through transmission charges." In our opinion, that reasoning is unsound, because:

- whether retailers pay transmission charges directly or indirectly (i.e., via a distributor) should not influence materially their incentive to scrutinise transmission costs – all that matters is whether they pay;
- it is likely to overstate the difference between retailers' and distributors' incentives to scrutinise transmission costs in any event, since both are likely to be in a position to pass-through 100% of transmission costs;
- retailers have been scrutinising transmission proposals for years despite the fact that they do not directly pay transmission charges to Transpower – as have distributors, despite transmission charges being "pass-through" costs;
- it does not matter whether distributors understand the SPD method, or how the wholesale market operates – what matters is whether they can forecast charges with reasonable accuracy; and
- the changes that the EA has proposed to its approach – particularly the move to a more predictable, less volatile ex-ante charge should enable distributors to better predict transmission charges.

148. Charging retailers instead of distributors would therefore seem to offer no obvious benefits. However, there would be costs. Most notably, Transpower would need to enter into a series of new contracts with retailers for the use of the transmission system. This would entail significant additional transaction costs. Moreover, as we noted in our first report, the EA's proposal would heighten risks for retailers – disproportionately so for smaller retailers without "natural hedges". Charging retailers is therefore likely to entail additional costs for no obvious benefits.

Appendix A Relevance of Benefits

149. In competitive markets, prices are determined by the interaction of supply and demand.[54] Consumers will demand a product when the private benefit they derive from consuming it exceeds the price that must be paid, taking into account the other consumption opportunities.[55] Firms will supply a product when the revenue earned from supplying it exceeds the costs that must be incurred to produce it, including a return on capital,[56] taking into account the other production opportunities.[57]

150. The concept of "beneficiary pays" is therefore subsumed into the market resource allocation process, which determines that the value a customer receives from a good or service sets the price above which she cannot be charged. This appendix explores the continuing relevance and application of this beneficiary pays principle in a natural monopoly setting, by expanding upon the material set out in sections 2.1 and 2.2 of this report.

A.1 Unregulated Monopoly Pricing

151. Figure 3 illustrates the familiar scenario in which a monopolist maximises its profits by restricting output – in this case to 40 units,[58] giving rise to a price of $6 ($P_M$). At this price there is a significant number of customers whose demand goes unserved, whom would have been willing to pay a price that would still have covered the costs the firm would have incurred producing the extra output (a constant $2 per unit). By increasing its price above its cost of supply ($2), the firm causes:

54 When substantial market power exists, the price at which firms are prepared to offer their output is determined not only by their costs of production, but also by the willingness of its customers to keep buying the product as it gets more expensive.

55 The law of demand states that as the price of a product increases consumers will buy less of it (and vice versa). This is because there will be more customers who do not value the product sufficiently highly to pay the higher price.

56 In principle, the return on capital is determined based on the returns that would be earned if resources were diverted to alternative production opportunities in other markets.

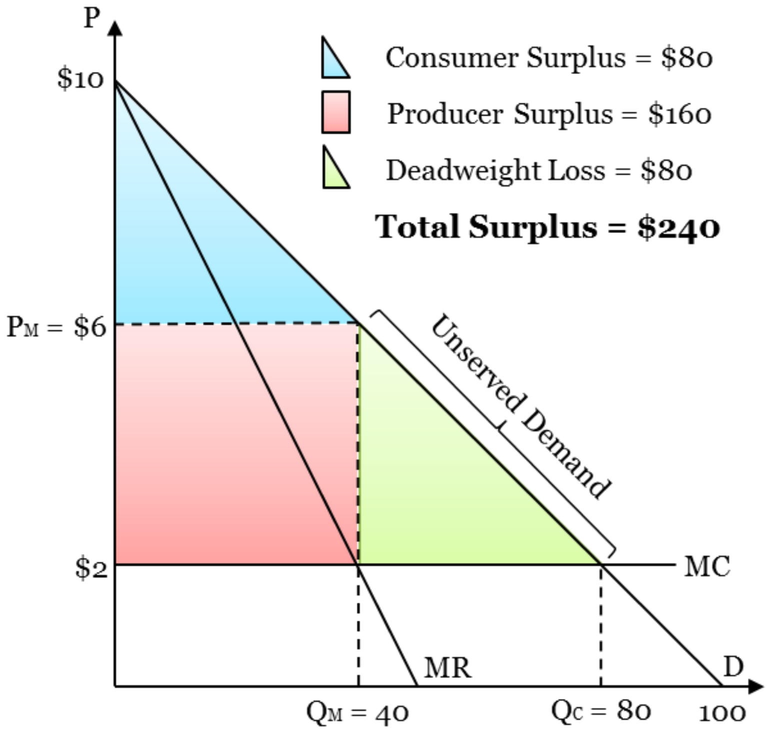
57 The law of supply states that as the price of a product increases, more will be supplied. This is because the higher revenue implied by the increased price may justify dedicating more resources to produce a greater quantity of that product. Moreover, because firms generally employ the cheapest available inputs, as output expands, those key ingredients can become scarce and more expensive.

58 This is where its "marginal revenue" (MR) equals its "marginal cost" (MC), i.e., where the additional revenue it makes from the sale of one more unit is equal to the additional cost it incurs in producing that unit. If the revenue that the monopolist would earn from selling one more unit exceeds the cost of producing it, then it is better off expanding its output and producing that additional unit. Similarly, if the revenue that the monopolist earned from selling its last unit was less than the cost of producing it, then it would increase its profits by cutting back its production and selling fewer units.

- $160 in surplus to be transferred from consumers to itself, i.e., a transfer of consumer[59] to producer surplus[60] (represented by the red rectangle); and
- $80 in consumer surplus to be lost altogether, i.e., a "deadweight loss" that is not recovered by anyone else (represented by the green triangle).

152. The former is a bare transfer of wealth, and so is of no consequence for overall efficiency – it is "welfare neutral". It is the latter – the "deadweight loss" from unserved demand – that motivates regulation. If the firm is required to set more "cost reflective" prices, it is possible to generate additional consumer surplus that is not predicated on an *equivalent reduction* in producer surplus. This is achieved by reducing the size of the green triangle in Figure 3.

Figure 3 Single Monopoly Price



153. By reducing deadweight loss, it is possible to make someone better off without making someone else equally worse off. This is known in economics as a "Pareto improvement". This gain is attainable because the private benefit that consumers

59 At a price of $6 there are still infra-marginal consumers who would have been prepared to pay more for the product, i.e., whom derive more than $6 in private benefits. This margin is known as "consumer surplus" and is represented by the blue triangle.

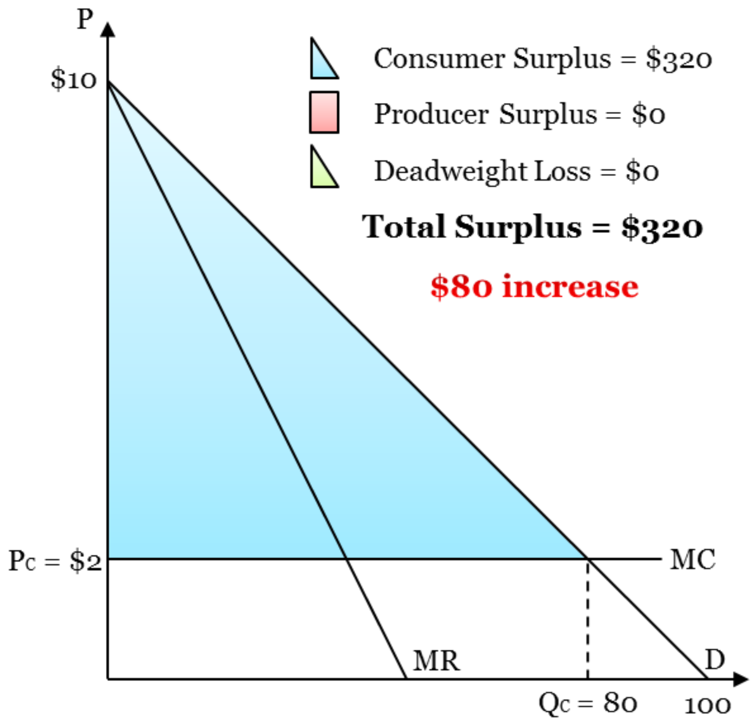
60 At a price of $6 there are infra-marginal units that would have cost less than $6 each to supply, enabling the monopolist to make an "economic profit" on each unit sold. This margin is known as "producer surplus" and is represented by the red rectangle.

obtain from the extra units the monopolist supplies exceeds the marginal cost of producing them. Consider, for example, the scenario in which the monopolist is required to sell all of its output at its short-run marginal cost of $2 per unit.

A.2 Marginal Cost Pricing

154. By requiring the monopolist to set its price equal to marginal cost, consumer surplus is maximised, increasing from $80 to $320. On the other hand, producer surplus drops from $160 to $0. Consumers therefore benefit at the expense of the firm, but that is not the objective. Rather, the goal is to eliminate inefficiently unserved demand. That previous $80 deadweight loss no longer exists. The net result is that consumer surplus increases by *more* than producer surplus decreases, yielding an $80 uplift in overall static efficiency.

Figure 4 Single Marginal Cost-based Price



155. Of course, the problem with the marginal cost pricing depicted in Figure 4 is that, if the firm has any fixed costs, they will not be recovered. Rather, the firm will make an economic loss over the long run. The conventional way for this to be overcome when setting regulatory prices so as to allow a firm to recover its total costs (i.e., including fixed costs) is to employ a two-part tariff.

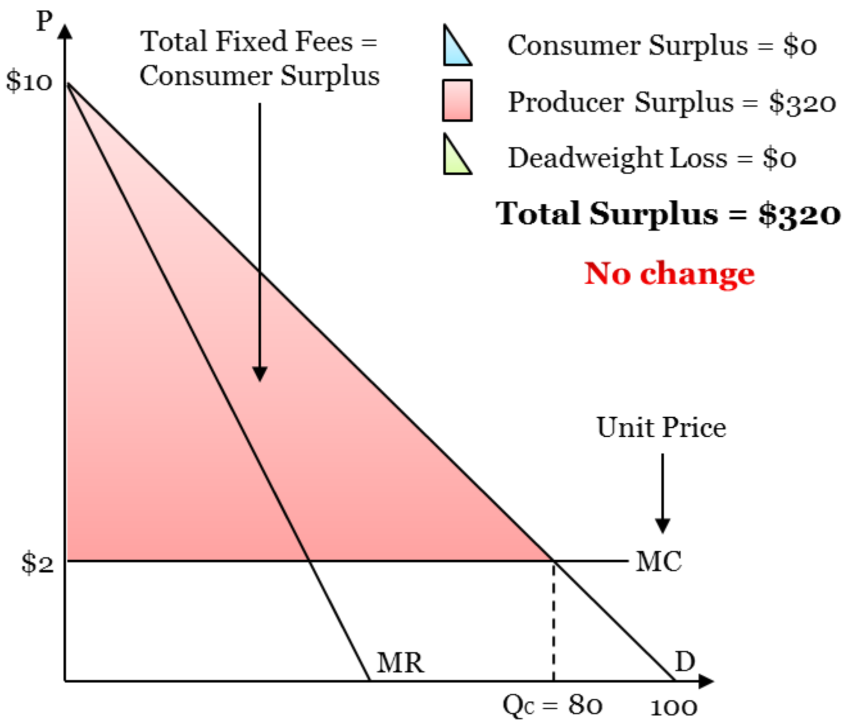
A.3 Two-part Tariff

156. Imagine, for the sake of illustration, that the firm had fixed costs were exactly equal to the quantum of consumer surplus in Figure 4, i.e., $320. Suppose also that the firm had "perfect information" about how much each consumer benefited from the product, i.e., their private benefit. Equipped with that information, the firm could implement a "two-part tariff", whereby:

- it set a "unit price" for its product equal to its marginal cost ($2), which would serve to maximise demand, just as in Figure 4; and
- to recover its fixed costs of $320, it could charge each consumer a fixed fee that was exactly equal to their individual consumer surplus.

157. In other words, having maximised consumer surplus via the $2 marginal cost based usage charge (as in Figure 4) the firm then *takes all of that surplus away* through the fixed fees. Figure 5 illustrates that the only difference to the previous example is that producers now benefit at the expense of consumers. But, critically, the $80 deadweight loss from unserved demand that featured in Figure 3 continues to be absent, producing the same $80 increase in total welfare.

Figure 5 Two-part Tariff



158. Importantly, from a short-term static efficiency perspective, the fact that the firm appropriates the entirety of the consumer surplus is irrelevant. What matters is the fact that there is *still no inefficiently unserved demand*. As we explained in our previous report in response to the EA's CBA working paper,[61] in the presence of fixed costs, this requires the application of the Ramsey-Boiteux pricing principle, which entails precisely the type of two-part tariff shown above, namely:[62]

- the price for an additional unit of the service in question set equal to the short run marginal cost of supplying it, so as to maximise demand; and
- fixed costs then recovered in a way that minimises distortions to demand, e.g., through fixed charges based on respective customers' willingness to pay.

159. The second criterion is perhaps the more crucial, since it is often the more difficult to implement. In the above example we overcame this problem by assuming the firm had perfect information about customers' willingness to pay. Of course, in practice, neither the firm nor the regulator will have that knowledge– at least not with any precision. The challenge, therefore, is to design charges that recover fixed costs without compromising the static efficiency created by the unit charge.

A.4 Minimising Distortions to Demand

160. There is not necessarily any "right way" to go about minimising distortions to demand – it all depends upon the circumstances. For example, if the quantum of fixed charges to be recovered in the previous example was, say, $100, instead of $320, there are many potential ways in which to recover that sum from customers. For example, the firm might seek to recover it all from a single customer, or seek to spread the cost across a broader base to minimise the incidence on particular users.

161. It is here that it is particularly important to make a distinction between *efficiency* considerations and *equity* considerations. For example, it may not seem equitable to send a bill for $100 to a single customer at the end of the period, given that others are using and likely to be benefiting from the service. However, that is not the relevant question when assessing the efficiency of the charge. The only pertinent question is: would that charge give rise to unserved demand?

162. The answer may well depend on the private benefit that the customer derived or perceives she will derive from consuming the service in question during the relevant period. Specifically, the customer may well ask: "did I, or will I, derive $100 in private benefits from consuming the service at $2 per unit?" If the answer to that question is "no", this may lead to distortions. For example:

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61 CEG, *Economic Review of EA CBA Working Paper, A Report for Transpower,* October 2013, §29.

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

- if the firm attempts to charge the customer a $100 annual fee in advance, she may decide that she is unlikely to derive sufficient private benefit that year to consume the service, leading to unserved demand in the current year; or
- if the firm sends the customer a $100 bill at the end of the year, she may decide that she did not derive sufficient private benefit that year to justify the extent of the charge, which may cause her to:
  - choose not to purchase the service the following year, for fear of attracting another charge of a similar magnitude; or
  - choose not to purchase as much of the service the following year, in an attempt to attract a smaller charge (depending upon how it is levied).

163. In all of the examples described above, levying the fixed fee gives rise to inefficient unserved demand, and the firm must also find another way to recover its fixed costs. One might therefore be tempted to conclude that the best approach is for the firm or the regulator to attempt to recover the fixed costs by levying charges on customers in proportion to their private benefits, e.g., if a customer is estimated to derive 5% of the total consumer surplus, it should be required to pay 5% of the fixed costs.

164. However, that is not necessarily so. For example, imagine that there are 100 customers and that the fixed costs are currently being allocated across them evenly, i.e., $1 each. Would changing the methodology so as to charge customers in proportion to their perceived benefit improve static efficiency? It might, or it might not. It depends upon a number of factors, including:

- the current level of deadweight loss from unserved demand, which may be quite modest if demand is highly inelastic, e.g., if the service in question is essential;
- the accuracy with which private benefits can be identified – if these are overestimated, it might lead to the same distortions described above; and
- whether it causes customers to change their consumption patterns so as to reduce the extent to which they are perceived to benefit.

165. As we illustrated in section 2, it is conceivable that the distortions arising from the second and third factors are materially worse than those associated with the first. In other words, attempting to introduce a "beneficiaries pay in proportion to benefit" approach may give rise to an even greater level of unserved demand and deadweight loss. Such approaches cannot simply be assumed to promote static efficiency based on observations from the completely different setting of a workably competitive market. What is required is a careful assessment of the above factors.

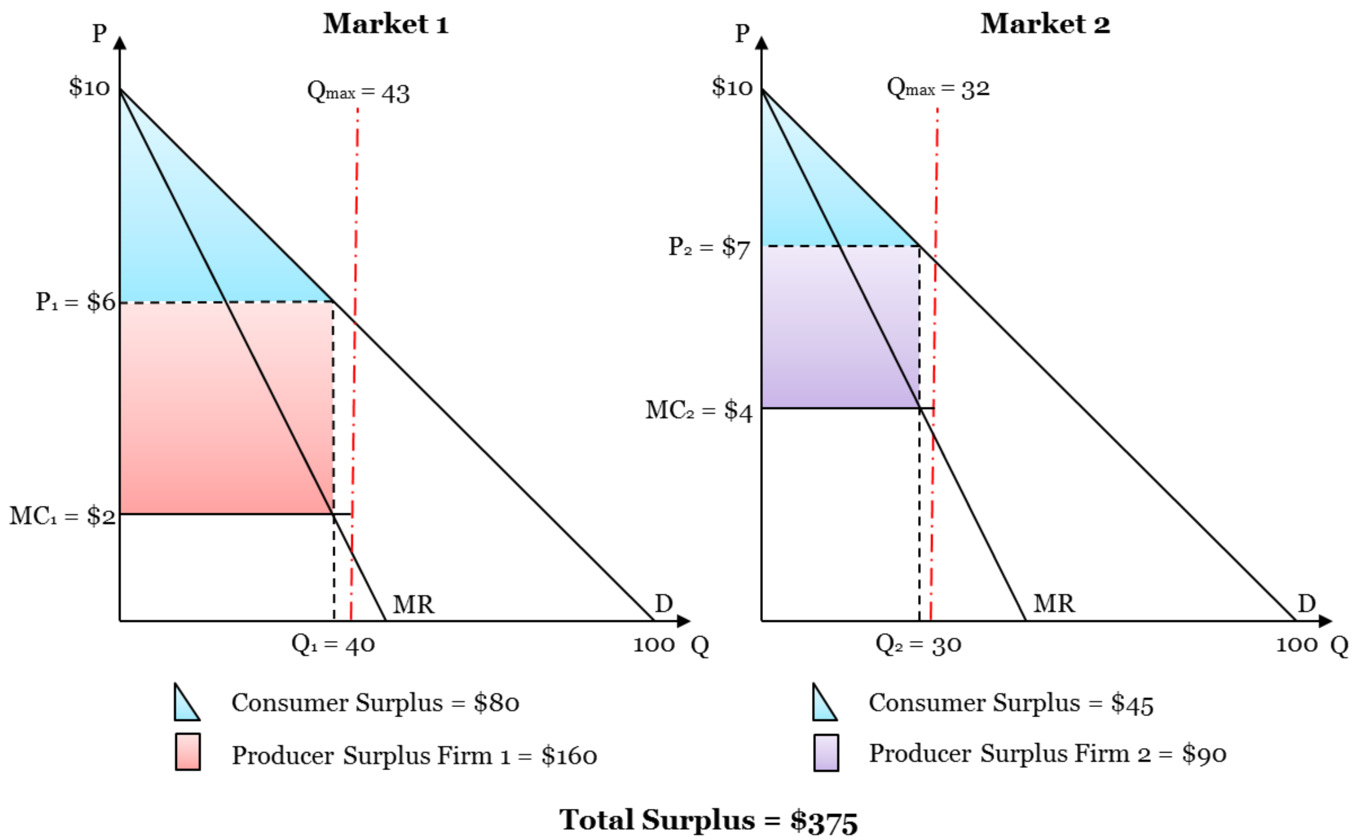
Appendix B Impact on New Investments

166. This appendix provides a simple quantitative illustration of why the EA's options would not provide with the Commission with an unambiguous indication of the best investment option. It shows why there would still be a range of submissions both for and against an efficient investment – motivated in every case principally by wealth transfers. It also provides a numerical illustration of why an actual Pareto improvement is required before a "uniform voice" can reveal the best outcome.

B.1 Separate Markets

167. Imagine that there are two firms supplying widgets – the first in market 1 and the second in market 2. Suppose also that the markets are geographically separate and that the firms are monopolists in their respective markets. As monopolists, the firms set their prices in the usual way, producing to the point at which their marginal revenue is equal to their marginal cost. Figure 6 illustrates the prices, quantities and welfare outcomes that arise in the separate markets.

Figure 6 Separate Markets

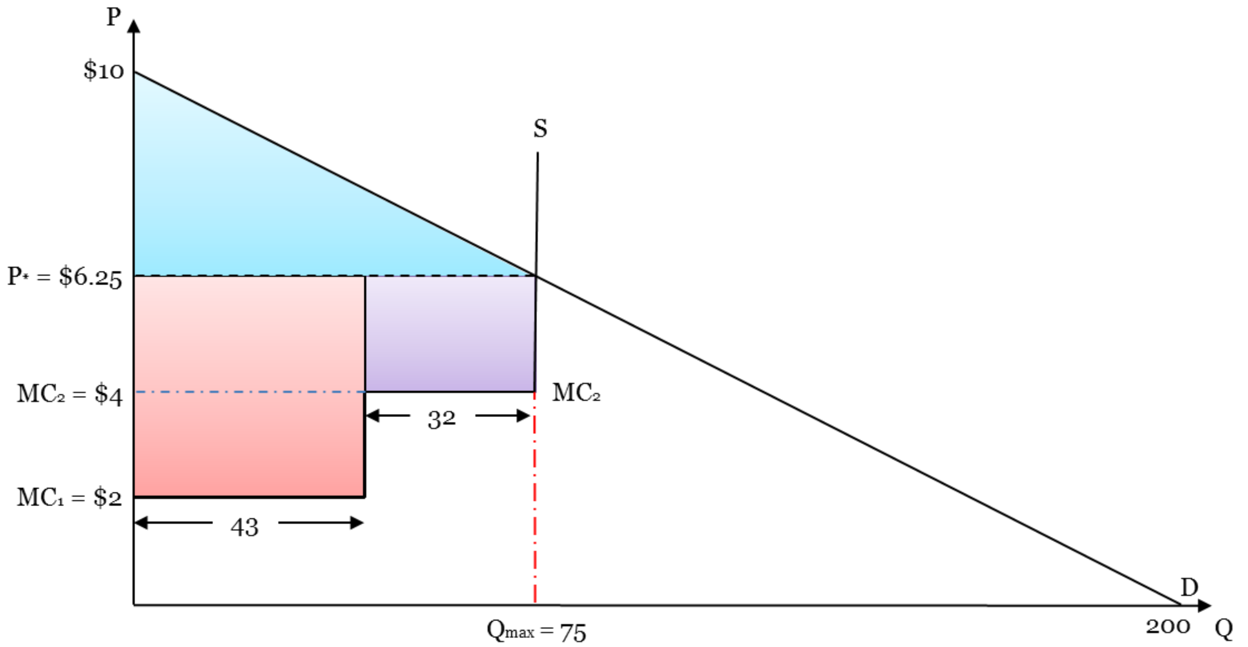


B.2 Markets Linked by New Investment

168. Now imagine that a proposal is made to build a road that links the two markets, forcing the two suppliers to compete with one another. For ease of exposition, suppose also that the road is free to build and that widgets can be transported between markets upon it at no cost. This results in a single market spanning the two geographic areas. In addition, imagine that competition between the firms is so fierce that each supplies its entire output at their marginal costs.

169. Finally, let us assume that when the firms offer their entire output at their respective marginal costs, there is excess demand. Buyers respond by offering higher and higher prices, which results in some customers who are not prepared to pay those higher prices "dropping out". This process "price rationing" continues until the market price is set where demand equals available supply. Figure 7 depicts the price, quantity and welfare outcomes in the combined market.

Figure 7 Markets Linked by New Investment



Consumer Surplus = $140.63 → $15.63 increase → Market 1 consumers pay 25c more & are **harmed** / Market 2 consumers pay 75c less & **benefit**

Producer Surplus Firm 1 = $182.75 → $22.75 increase → Firm 1 **benefits**

Producer Surplus Firm 2 = $72 → $18 decrease → Firm 2 **harmed**

$20.38 increase in total surplus to $398.38

170. Figure 7 reveals that building the road can give rise to a Pareto improvement, i.e., the combined total consumer and surplus is $20.38 higher with the road than without it. However, that does not mean that there would be universal support for that efficient investment. Instead, the key stakeholders would be evenly split, with two supporting the construction of the road and two opposing it. Specifically:

- the firm from market 2 receives a lower price and the consumers from market 1 pay a higher price, and so both oppose the construction of the road; whereas
- the firm from market 1 receives a higher price and the consumers from market 2 pay a lower price, and so they are both in favour of the road.

171. In other words, simply looking at the submissions from the parties will not reveal whether it should be built. They will contain conflicting messages and will be motivated primarily by the effect of wealth transfers, rather than by the overall gain in welfare that can be achieved. It will therefore require a separate party to make a judgement about the efficiency of the road from a whole-of-market perspective.

172. The only way to obtain unanimous support for the project is if the net beneficiaries – in this case the firm from market 1 and the consumers from market 2 – compensate the losers for their reduction in surplus. For example, firm 1 would need to pay $18 of its $22.75 increase in producer surplus to firm 2, in order to compensate it for the reduction in welfare that it would otherwise experience.

173. That way, firm 1 would still be $4.75 better off due to the road, but firm 2 would no longer be worse off. A similar transfer would also be needed to compensate the consumers in market 1. Only by creating an actual Pareto improvement in this manner will there be unanimous support for an efficient investment that obviates the need for a third party – such as a regulator – to exercise its judgement.