



Economic Review of Second Transmission Pricing Methodology Issues Paper

A Report for Transpower

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Abbreviations

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIC	Average Incremental Cost
ATC	Average Total Cost
Axiom	Axiom Economics
CBA	Cost-benefit Analysis
Commission	Commerce Commission
EA	Electricity Authority
EDB	Electricity Distribution Business
LNI	Lower North Island
LRMC	Long Run Marginal Cost
LSI	Lower South Island
NPV	Net Present Value
OGW	Oakley Greenwood
OGW CBA	Oakley Greenwood Cost-benefit Analysis
RCPD	Regional Coincident Peak Demand
SRMC	Short Run Marginal Cost
TPM	Transmission Pricing Methodology
UNI	Upper North Island
USI	Upper South Island



Executive summary

This report has been prepared by Axiom Economics (Axiom), on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (EA's) proposed reforms to the transmission pricing methodology (TPM), as set out in its Second Issues Paper (Issues Paper).¹ In evaluating the proposed reforms, Transpower has asked us to review and comment from an economic perspective on the analysis and conclusions contained in the Issues Paper and the accompanying report by Oakley Greenwood, which contains a quantitative cost-benefit analysis of the proposed reforms (the 'OGW CBA').²

In our opinion, the proposed reforms set out in the Issues Paper are superior to the other beneficiaries-pay approaches the EA has suggested previously throughout the consultation process, although some potentially intractable problems remain. Some of the key positive attributes of the proposed methodology include the following:

- if implemented, the proposal would create an incentive for customers to increase demand in areas in which there is currently spare transmission grid capacity (although, this could also be achieved through more incremental reform);
- with some exceptions, the time profile of the proposed area of benefit (AoB) charge is likely to be more efficient (and 'service-like') than the charges set out in the previous Options Paper – including the previous variant of the AoB charge itself; and
- Transpower has some discretion over important aspects of the methodology, including how to define the 'areas of benefit', which would allow it to make pragmatic decisions to make the approach as practicable as possible.

The proposal is superior to previous approaches, but several key issues still need to be addressed.

The extent to which the proposal would ultimately represent an improvement upon the status quo depends to a critical extent upon whether some key issues can be addressed. Starting from first economic principles, efficient transmission pricing requires two distinct price signals to be sent to customers:³

- the first is a signal that is sent to customers *before* an investment is made to elicit desirable changes in behaviour; and
- the second is sent *after* an investment has been made, and should be designed to *minimise* those customers' incentives to change their behaviour.

The basic premise in the Issues Paper is that both of these signals could be sent through a single AoB charge and that the residual charge would cause no

¹ Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper*, 17 May 2016 (hereafter: 'Issues Paper').

² Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority*, 11 May 2016 (hereafter: 'OGW CBA').

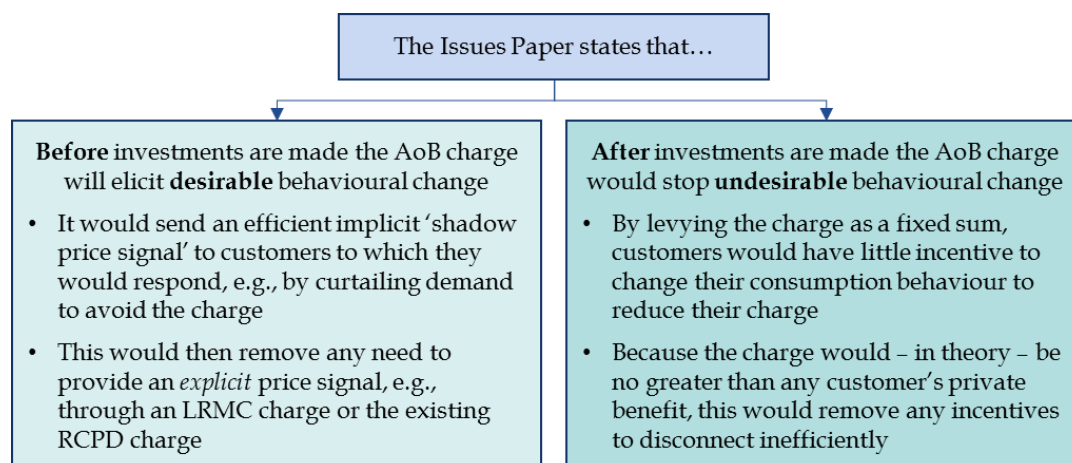
³ See: Green *et al*, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §2.2; Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §2.2; and Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, §2.2.1.



behavioural change (i.e., it would assist only in efficient cost recovery). Moreover, the paper posits that those signals would be more efficient than those provided by the RCPD-based interconnection charge and the HVDC charge contained in the current TPM. Figure ES.1 below summarises.

Figure ES.1: Two efficient price signals in a single charge

The AoB charge is said to be able to provide both aspects of an efficient two-part tariff. We do not consider it would achieve either objective in its present form.



In our view, an AoB methodology would not achieve either of these objectives – at least not in the way it is framed currently. Rather, we consider that:

- as an *ex-ante* signal, the charge could *not* elicit desirable behavioural change because customers would not be able to predict the future prices they would pay, those prices would not reflect each customer's impact upon Transpower's forward-looking costs, and they might (rationally) be disinclined to respond to those signals in any event because of the potential actions of others; and
- the extent to which it could give rise to a less distortionary *ex-post* allocation of sunk costs would depend upon many factors, including the way in which private benefits were estimated.

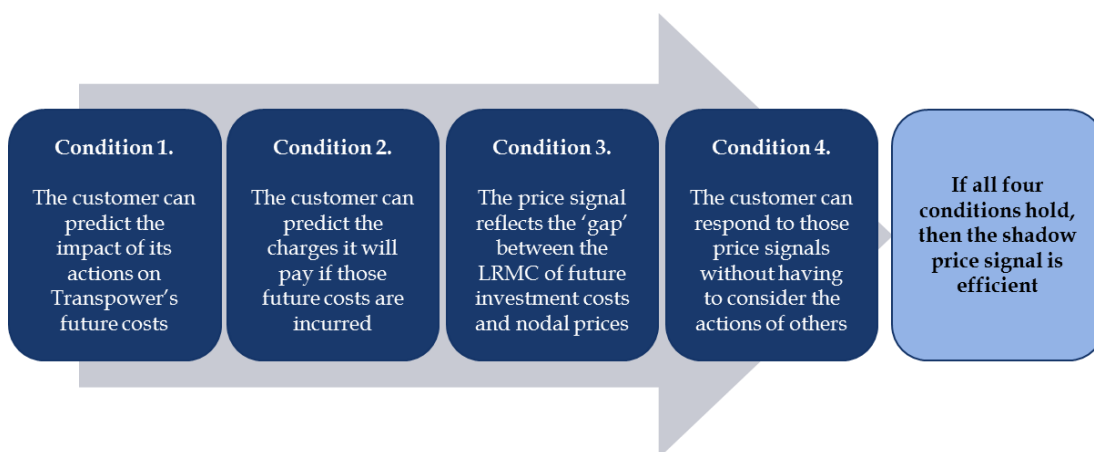
We also consider that the proposed residual charge has the potential to be distortionary, and that extending prudent discounts to firms said to be at risk of exiting is problematic. We explore each of these matters in turn below, before describing how they might be addressed, in practice. We conclude by explaining why the OGW CBA does not provide any guidance as to the benefits and costs of the methodology and cannot be relied upon to justify the proposed changes.

The AoB charge would not provide an efficient price signal

The Issues Paper proposes that although customers would only pay AoB charges *after* an investment had been made, the prospect of doing so would be sufficient to motivate efficient consumption and investment responses from both generation and load *before* that point. In other words, it would provide an efficient 'shadow' price signal. However, for that to be the case, four key conditions would need to hold, as Figure ES.2 illustrates.



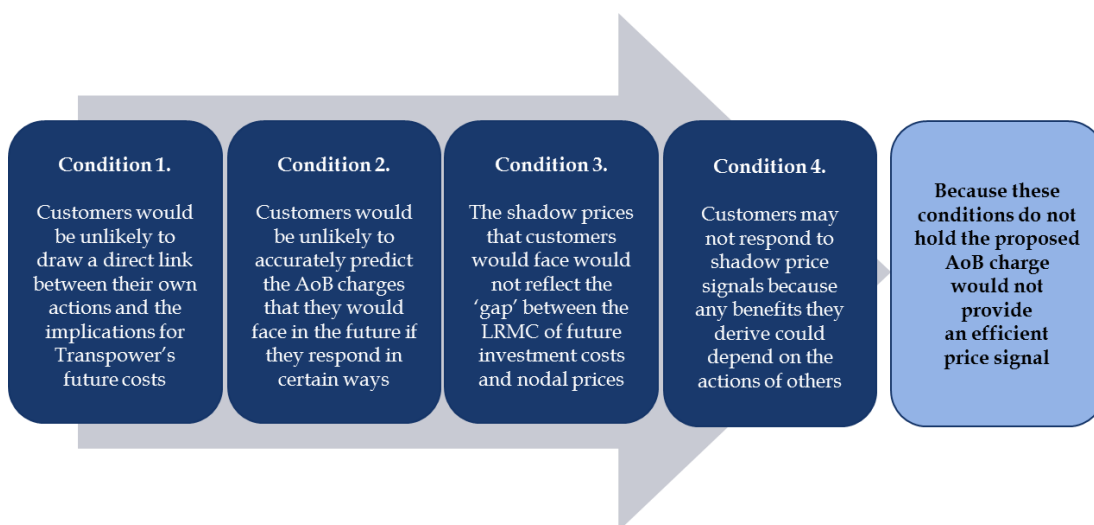
Figure ES.2: Conditions for an efficient implicit shadow price



The four key conditions for an efficient shadow price do not hold in the case of interconnection assets.

These conditions could apply in the case of connection assets, where investment needs tend to be clear, and it is often the actions of one party driving the investment need. However, they do *not* hold for *interconnection* assets. That is because, as Figure ES.3 illustrates, it would not be possible for customers to gauge the effects of their actions on Transpower's future costs and the AoB charges they would pay. Even if they could, they may not respond to those signals, because of the potential actions of others – and they would not be cost-reflective in any event.

Figure ES.3: The conditions for an efficient shadow price do not hold



Expected private benefits are not synonymous with forward-looking costs.

The third condition described above is of particularly importance in this context because, even if customers could predict the AoB charges that they would pay in the future (which we think is unlikely) and could ignore the actions of other customers, those charges would still not reflect forward-looking transmission costs. To see why, imagine that two customers saw that there was a \$100m investment on the horizon. The shadow prices that they perceived might be quite different:

- if customer A thought it would be assessed as receiving 80 per cent of the private benefits, it would expect to pay \$80m in AoB charges in total; and
- if customer B estimated that it would be assessed as receiving 20 per cent of the benefits, it would expect to pay AoB charges totalling \$20m.



In this simple example, the shadow price signal perceived by customer A is *four times stronger* than customer B's. However, it does not follow that demand curtailment from customer A is four times more valuable (or that incremental demand is four times as costly). Rather, 100kVA of peak load reduction from customer A or B might deliver *the same long-run cost saving*. Yet, despite this, the AoB charge could provide them with completely different signals.

The AoB charge might cause customers to make inefficient consumption and investment decisions.

The proposed 'marginal benefit adjustment mechanism' could not be relied upon to address these problems and produce efficient outcomes. For example, if customers A and B from the previous example can each only provide 50kVA of peak load reduction, but 100kVA is needed to downsize an investment, then that benefit would be lost.⁴ The mechanism could also complicate and disrupt Transpower's investment planning processes.

In summary, even if customers could accurately predict their AoB charges, and safely ignore the actions of other customers, there is no basis to presume they would make efficient consumption and investment decisions. Private benefits are *not synonymous* with forward-looking costs. The AoB charge might instead cause load and generation to make *inefficient* consumption and investment decisions, and hinder the new investment process, as Table ES.1 summarises.

Table ES.1: Potential inefficiencies arising from the inefficient price signal

	Load	Generation
Operation	<p>Because the four key conditions described above do not hold, the AoB charge would not enable Transpower to send efficient signals to customers to curtail demand when constraints start to re-emerge in the future.⁵</p> <p>This could result in Transpower having to invest to alleviate constraints sooner than it would otherwise have needed to if an explicit price signal had been sent to customers via the TPM.</p>	<p>Levying AoB charges on generators would increase their operating costs and, in turn their 'break-even' points. This would result in higher wholesale prices to cover those increased costs.</p> <p>It is unlikely that those higher wholesale costs would be off-set by long-term transmission cost savings because, as we note below, the AoB charge would be unlikely to incentivise efficient new investment decisions.</p>

⁴ This scenario is referred to as a 'tragedy of the commons', i.e., where parties acting rationally in their individual interests, give rise to an outcome that is inefficient for all. It is also worth noting that the 'marginal price signal' contemplated in the Issues Paper would be relatively unsophisticated in that it would only be providing an explicit price signal at *one point in time*, i.e., once Transpower presents customers with an 'investment proposal'. Unlike, say, an LRMC charge (which can fluctuate over time), that signal will only be one strength – presumably 'very strong', assuming that 'investment proposals' relate only to investments to be made relatively soon.

⁵ Although inefficient load-shedding would cease in the near-term if the proposal was implemented, this would be on account of the removal of the RCPD charge, not the introduction of the AoB charge.



	Load	Generation
Investment	Levying AoB charges on load customers is unlikely to affect their locational decisions since, in the vast majority of circumstances, other factors would have a far greater bearing. For example, residential customers do not decide where to live based on transmission charges, and the locational decisions of large industrial customers will generally be swayed by practical factors such as the location of forests, ports, etc.	Because the four key conditions described above do not hold, the AoB charges would not provide generators with an efficient price signal – especially because expected private benefits are not synonymous with forward-looking transmission costs. The proposal would also send the counterintuitive signal that it is cheaper for generators to locate where assets were built before 2004. This would be likely to compromise dynamic efficiency.
Engagement in grid investment processes	If the AoB charge is introduced, both load and generation customers would have stronger incentives to oppose <i>all</i> investments – including those that maximise net market benefits – and advocate for alternatives that may be less efficient, but would maximise their own private benefits. The requirement to recover the costs of an investment based on estimated private benefits over the life of an investment would serve to exacerbate the scope for disputes. Customers would naturally focus on modelling assumptions that have affected them adversely. This additional unconstructive opposition could compromise dynamic efficiency if it results in ‘good’ investments being blocked.	

The AoB charge therefore does not meet the *first* objective of efficient transmission pricing. Namely, it would not provide an efficient signal to customers of future costs before investments are made to elicit desirable changes in behaviour. Any benefits from the AoB charge would consequently need to reside in its ability to meet the *second* objective of efficient transmission pricing, i.e., minimising distortions to demand *after* investments have been made.

The AoB charge may not result in a more efficient allocation of sunk costs

The Issues Paper suggests that the AoB charge would give rise to a more efficient allocation of sunk costs. In our view, that is unlikely to be the case, since an AoB charge would appear not to address any of the distortions that currently arise from the RCPD and HVDC charges.⁶ However, the significant reallocation of sunk costs of existing assets to load customers that is contemplated in the Issues Paper could certainly result in static efficiency losses.

For example, it is hard to imagine that allocating around \$850m (in NPV terms over 20-years) to load customers would not give rise to at least *some* reduction in demand – even if that increase is only partially passed-through in volumetric charges.⁷ Even

It is unclear whether the AoB charge would produce a more efficient sunk cost allocation.

⁶ At least once the inefficiencies associated with the RCPD charge are addressed which, as Figure ES.4 illustrates, can be achieved through other means.

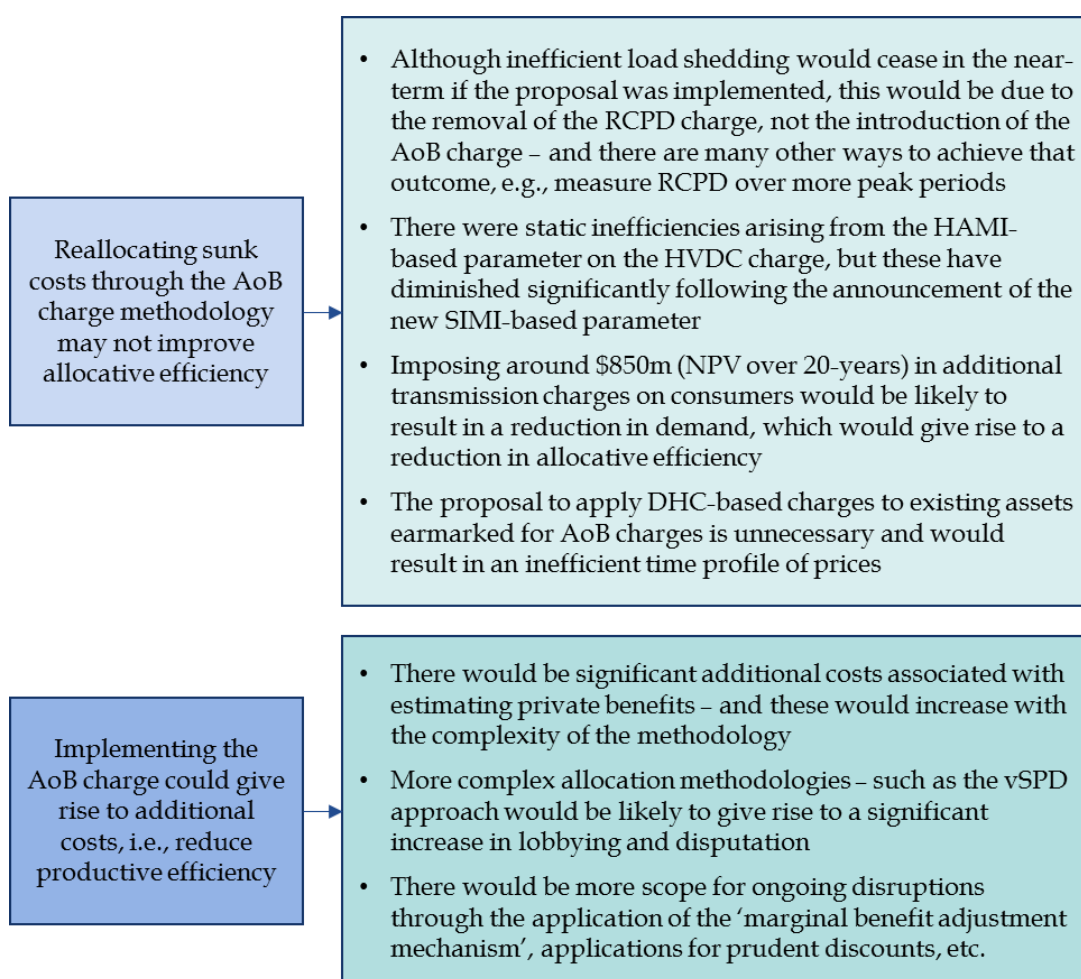
⁷ Note that a considerable proportion of this total (around \$750m of the \$850m) is accounted for by the reallocation of the HVDC charge.



if there is only a modest increase in inefficiently unserved demand, this could amount to a significant allocative efficiency loss over the 20-year assessment period.

Implementing the methodology could also give rise to significant additional ongoing administrative costs, which would reduce productive efficiency. Many of these stem from the requirement to estimate private benefits over the *entire life* of an investment. More complex methodologies – such as the vSPD approach – would entail the greatest costs but, in our view, would not necessarily arrive at a more accurate estimate of private benefits. Figure ES.4 illustrates.

Figure ES.4: Potential effects on static efficiency and administrative costs



It is conceivable that the proposed cost allocation methodology might be perceived to be ‘fairer’ than the existing approach – which is virtuous in its own right, and may serve to improve the durability of the arrangements. However, equity is an intrinsically subjective concept. There also seems little doubt that any such benefits would be accompanied by additional costs which would offset those advantages – and, possibly, significantly outweigh them.

Moreover, it is important to recognise that transmission pricing was a source of controversy well before the current TPM was put in place and will continue to be



irrespective of the methodology that is ultimately put in place.⁸ This is an unremarkable consequence of the economics of transmission. Changes in the TPM that have only modest efficiency implications can still give rise to large transfers of wealth. It is therefore only natural that profit maximising firms have lobbied continuously to have the methodology changed in their favour.

Residual charge allocation and the prudent discount policy

The residual charge may be distortionary and seen as unfair.

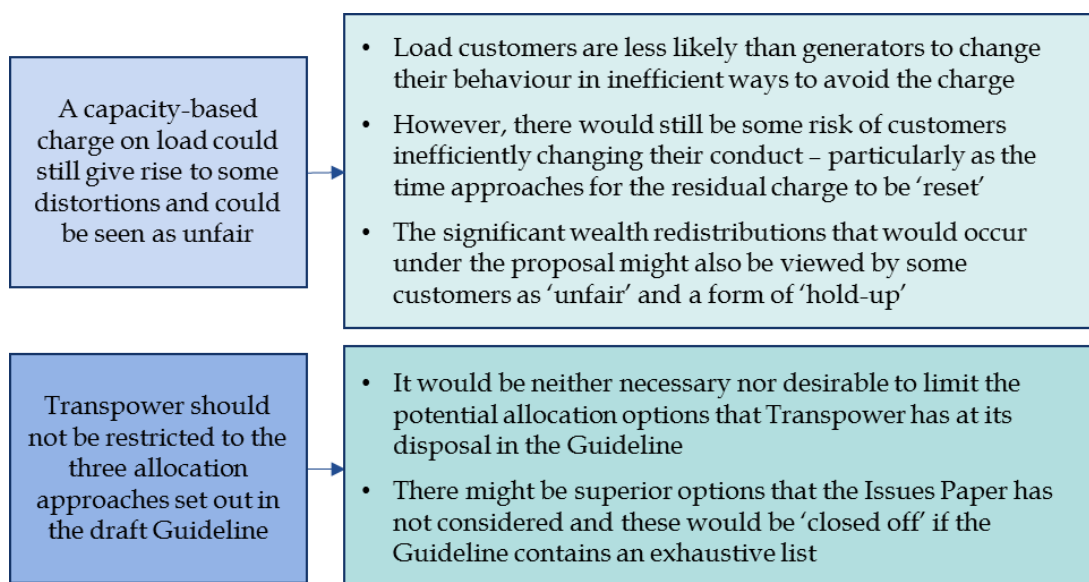
We agree that levying a residual charge on load customers is likely to be the best approach if the proposal is implemented. However, the three capacity-based allocations that have been proposed might still give rise to distortions, could be viewed as 'unfair' given the significant wealth transfers they would generate, and might not be the most efficient options available.

The Issues Paper does not set out the reasons why alternative options for allocating the residual to load have been ruled out. In our opinion, *all* potential allocation methods should be considered – either by the Authority in setting the Guidelines, or tasked to Transpower to review as part of development of the TPM itself.

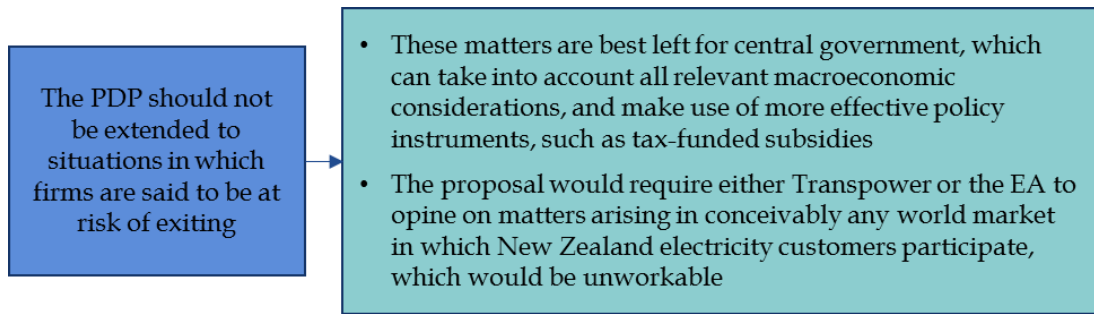
The PDP should not be extended to address firms at risk of exiting.

Finally, we do not consider that it is necessary or appropriate to extend prudent discounts to firms said to be at risk of exiting the market unless their input costs decrease. Neither Transpower nor the EA would be well placed to adjudicate on such matters in practice, and so they should be left to central government. Figure ES.5 summarises our conclusions on the residual charge.

Figure ES.5: Assessment of the proposed residual charge and PDP



⁸ For example, Contact and Meridian launched a successful judicial review of the process the EA's predecessor undertook to arrive at its 2005 pricing guideline, see: *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J). For an overview of the process by which the current TPM was determined – including the various controversies, see: Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.17.



For the reasons set out above, in its present state, the proposal in the Issues Paper would be unlikely to improve upon the status quo. However, in our view, it may be possible to address some of these key issues with the proposed methodology. In some cases, this could be done with relatively minor changes to the draft Guideline and, in others, more material revisions would be needed.

The Oakley Greenwood cost-benefit analysis is not robust

The modelling in the OGW CBA does not provide a robust indication of either the benefit or costs of the proposal. It rests on three key foundational assumptions:

The modelling in the OGW CBA does not provide a robust indication of either the benefit or costs of the proposal.

- that the AoB charge would provide an efficient *ex-ante* price signal, i.e., that it would provide an accurate and predictable indication to customers of the potential consequences of their actions on Transpower's future costs;
- that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand; and
- that the AoB (and deeper connection) charges that that each market participant (e.g., individual generators) would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, e.g., UNI, LNI, USI and LSI.

None of these assumptions holds, since:

- as Figure ES.3 and Table ES.1 illustrated, the implicit shadow price provided through the AoB charge would be an *inefficient* price signal that risks compromising static and dynamic efficiency;
- even if only a modest proportion of the additional costs that would be allocated to load customers were passed-through as volumetric charges, this would be likely to result in a significant allocative efficiency loss; and
- the prices that market participants would pay under the AoB charge would *not* be equal to an estimate of the regional LRMC of transmission – each unit would face a unique price that may be more or less than LRMC.

Furthermore, by assuming that the AoB charges would be 'perfectly efficient' (i.e., send an efficient *ex-ante* price signal, and be non-distortionary *ex-post*), the model *must* conclude that future generation and transmission costs would be lower. All it is doing is working out how big this benefit is – which is not an appropriate approach, when carrying out this type of analysis. The modelling of benefits itself also entails many unreasonable input assumptions, as Figure ES.6: illustrates.



Figure ES.6: Key input assumptions underpinning the OGW CBA





The modelling therefore does not reflect accurately the proposed AoB charge methodology (including its inefficiencies), the way in which the electricity system functions or the manner in which its participants make decisions. It follows that no weight can be placed on the resulting estimates of benefits to justify the proposed adoption of this methodology. Furthermore, for the reasons set out above, the various other ‘unquantified’ benefits identified in the Issues Paper would not be material – and, in many cases, would not be positive.



1. Introduction

This report has been prepared by Axiom Economics (Axiom), on behalf of Transpower. Its purpose is to evaluate the Electricity Authority's (EA's) proposed reforms to the transmission pricing methodology (TPM), as set out in its Second Issues Paper (Issues Paper).⁹ In evaluating the proposed reforms, Transpower has asked us to review and comment from an economic perspective on the analysis and conclusions contained in the Issues Paper and the accompanying report by Oakley Greenwood, which contains a quantitative cost-benefit analysis of the proposed reforms (the 'OGW CBA').¹⁰

In our opinion, the proposed reforms set out in the Issues Paper are superior in many respects to other approaches previously suggested throughout the consultation process. Some of the key positive attributes of the proposed methodology include the following:

- if implemented, the proposal would create an incentive for customers to increase demand in areas in which there is currently spare transmission grid capacity (although, this could also be achieved through more incremental reform);
- with some exceptions, the time profile of proposed 'area of benefit' (AoB) charge is likely to be more efficient (and 'service-like') than all of the charges set out in the previous Options Paper – including the previous variant of the AoB charge itself; and
- Transpower has some discretion over important aspects of the methodology, including how to define the 'areas of benefit', which would allow it to make pragmatic decisions to make the approach as practicable as possible.

The proposal is superior to many of the other reforms that have been proposed throughout the consultation process.

However, the extent to which the proposal would ultimately represent an improvement upon the status quo depends upon whether some key issues can be resolved satisfactorily. In particular, in our opinion:

- the AoB charge would not provide an efficient *ex-ante* price signal and so, in the absence of an LRMC price (or a modified version of the RCPD charge), there would be no way for Transpower to efficiently signal its *future costs*:
 - the AoB charge is not an orthodox, explicit *ex-ante* signal (like, say, an LRMC price) because parties would only pay the price *after* an investment had been made, i.e., it is more accurately described as an *ex-post* cost allocation; and
 - there are many reasons why parties either would not or could not factor this type of 'implicit shadow price' into their decisions *today* and, even if they could, those price signals would not be efficient in any event;

⁹ Electricity Authority, *Transmission Pricing Methodology: Issues and proposal, Second issues paper*, 17 May 2016 (hereafter: 'Issues Paper').

¹⁰ Oakley Greenwood, *Cost Benefit Analysis of Transmission Pricing Options, prepared for: NZ Electricity Authority*, 11 May 2016 (hereafter: 'OGW CBA').



A number of issues would still need to be addressed before the proposal could potentially improve upon the status quo.

- if a complicated modelling approach is used to measure benefits and allocate costs under the AoB charge (the ‘nodal’ vSPD approach used in the Issues Paper, for example), then this would be problematic, because:
 - complex modelling approaches may be no more likely to arrive at accurate estimates of private benefits than more pragmatic approaches, i.e., increased granularity will often simply represent ‘false precision’; and
 - such modelling would be costly to undertake and would give rise to significant scope for ongoing disputes, as parties challenge the various assumptions that have been used to derive their charges;
- the design of the residual charge may give rise to unintended adverse changes to parties’ conduct, and there may be less distortionary allocation mechanisms available than those proposed in the draft Guidelines; and
- it is neither necessary nor appropriate for either Tranpower or the EA to be granting prudent discounts to firms said to be at risk of exiting – these are matters beyond their expertise, and more appropriately left for government.

In our opinion, unless these critical matters are addressed, the proposal in the Issues Paper would be unlikely to improve upon the current arrangements. The remainder of this report is structured as follows:

- **section two** recaps the two basic objectives of efficient transmission pricing, explains briefly how the existing TPM seeks to achieve those goals, identifies some potential shortcomings in the status quo and then explains the chief rationale for the proposed AoB charge;
- **sections three** explains why the implicit ‘shadow price’ provided by the AoB charge would not fulfil the ‘first limb’ of an efficient two-part tariff, since it would not provide an efficient or predictable signal to grid users of the consequences of their decisions on Transpower’s future costs;
- **section four** sets out some of the potential consequences of introducing an inefficient shadow price signal through the AoB charge – namely, it would risk distorting significantly the consumption and investment decisions of load and generation, compromising dynamic efficiency;
- **section five** considers whether the AoB approach might be an efficient way of allocating the sunk costs of investments, whether it might offer the benefit of providing a ‘fairer’ allocation methodology and whether it could give rise to additional administrative costs;
- **section six** considers the proposed design of the residual charge, including the efficiency and ‘fairness’ of the charge, whether other less distortionary options might be available and whether it is necessary or desirable to extend the prudent discount policy in the manner contemplated in the Issues Paper;
- **section seven** explains why the OGW CBA is not fit for its intended purpose (i.e., to inform a decision to implement substantial changes to transmission pricing) and sets out the errors and inappropriate assumptions that we have identified in the modelling;



- **Appendix A** explains in more detail why, unlike in a competitive market, the short-run marginal cost of transmission will be systematically lower than its long-run marginal cost, and the implications for efficient pricing;
- **Appendix B** contains a more detailed description of the OGW CBA modelling methodology, including a more exhaustive account of the key input assumptions and its implementation; and
- **Appendix C** provides a list of previous reports prepared by Axiom economists throughout the consultation process hitherto that we draw upon throughout this report.

Note that we have not reviewed the recommendations made in relation to the connection charge, loss and constraint excess (LCE) and static reactive (kvar) charges in this report. Finally, we stress that the opinions expressed throughout this report are our own and do not necessarily reflect the views of Transpower.



2. Economic efficiency and pricing

In this section, we recap the two basic objectives of transmission pricing. The first is to provide an efficient signal to customers of Transpower's *future* costs. The second is to recover the sunk costs of *past* investments in the least distortionary manner. We then explain briefly how the existing TPM seeks to achieve these objectives, and how the proposal in the Issues Paper would seek to do so through the AoB charging methodology and the residual charge.

2.1 Efficient transmission pricing

Efficient transmission pricing involves sending two distinct price signals.

Efficient transmission pricing requires two distinct prices to be sent to customers. The first is a signal that is sent to customers *before* an investment is made to elicit desirable changes in behaviour. The second is sent *after* an investment has been made, and should be designed to *minimise* those customers' incentives to change their behaviour. As we have explained in several previous reports,¹¹ one means of achieving these dual objectives is through a two-part tariff.¹²

2.1.1 Objective one: efficiently signal future costs

In terms of the first price signal, the *short-run* marginal cost (SRMC) of providing transmission services to customers is signalled through locational marginal prices ('nodal prices') and losses. However, as we explain in more detail in Appendix A, a critical difference between transmission services and a workably competitive market is that those short-term nodal prices will never signal the *long-run* marginal cost (LRMC) of adding capacity. As the EA has explained:¹³

'Although nodal pricing provides efficient short-run price signals for use of the grid, it does not provide efficient long-run signals. Reliance on nodal pricing is insufficient to promote efficient transmission investment because nodal pricing does not provide a sufficient price signal about the cost of the future transmission investment needed to supply changes in demand for transmission services.'

Nodal prices and losses do not provide an efficient signal to customers of Transpower's LRMC because, for a number of sound practical reasons,¹⁴ new investments are made before they reach that level. Nodal prices and losses therefore cannot be relied upon to provide efficient signals to grid users of the costs that Transpower will incur when it replaces or upgrades its assets. As Figure 2.1 illustrates, those price signals will be *too weak*.

¹¹ Frank. P. Ramsey, "A Contribution to the Theory of Taxation", *Economic Journal* (1927), pp.47-61.

¹² See: Green *et al*, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §2.2; Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014, §2.2; and Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, §2.2.1.

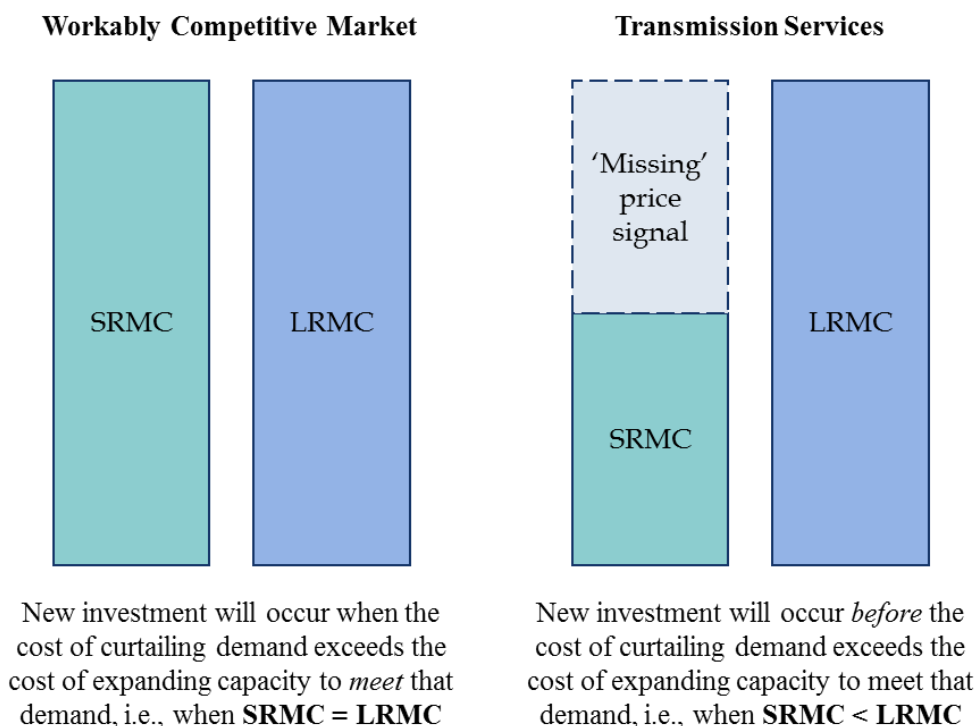
¹³ Electricity Authority, *Transmission Pricing Review, TPM options, Working paper*, 16 June 2015, p.53.

¹⁴ See: H. Fraser, 'Can FERC's Standard Market Design Work in Large RTOs?', *Electricity Journal*, Volume 15, Number 6, July 2002, p.25.



Figure 2.1: Gap between SRMC and LPMC

Nodal prices will systematically under-signal the LPMC of transmission resulting in a 'missing' price signal.



As Figure 2.1 highlights, there is a 'missing' price signal. In the absence of some other additional price signal, today's grid users will not factor into their consumption and investment decisions the potential consequences for Transpower's long-run investment costs. This can be expected to compromise dynamic efficiency. By way of simple example:

- a load customer may decide not to curtail its demand in a peak period in response to a higher nodal price (e.g., a 'higher' SRMC), but that incremental demand may 'bring forward' the need to undertake new investment; and
- because of the practical factors described above, that new investment will take place before nodal prices reflect the LPMC of that investment, in which case the load customer would *never* see the 'true costs' of its actions.

One way to address the 'gap' that exists between SRMC and LPMC is to provide transmission customers with an additional *explicit* price that signals to them the potential *long-run* costs of transmission. An obvious candidate is an explicit LPMC charge.¹⁵ There are many ways to calculate and apply such a charge, e.g., different methodologies, different geographical coverages, different targets (e.g., load and generation), and so on.

However, the basic objective of the charge (however specified) would be to provide customers with an additional *explicit* signal of the *future* costs that Transpower might incur through a price that they face *today*, which would serve to address any

¹⁵ For a further discussion of LPMC pricing, see: Green *et al*, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013, §3.3; Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, §6.1.



‘shortfall’ in nodal price signals. Take a simple example where growth in peak demand in location A meant that Transpower was facing the prospect of investing in new capacity between location A and B. It might decide to:

- levy an LRMC charge based on a marginal incremental cost approach on off-take customers in location A who consume during peak periods; and/or
- levy an LRMC charge on generators in location B – or even provide a credit (a negative tariff) to generators that produce during peak periods in location A.

The ‘missing’ price signal can be provided through an explicit forward-looking price, such as an LRMC charge.

Load and/or generation could then look at that additional explicit LRMC price and make immediate, informed decisions about the actions that are most likely to promote their own private benefit; most notably:

- off-take customer can decide whether it is worth curtailing demand to avoid the LRMC charge or if they are better off simply paying it;
- if the charge is applied to generators, this may encourage them to generate at times and in locations that are more likely to defer future transmission costs; and
- it is possible that the charge may also result in more efficient locational investment decisions by load and generation.¹⁶

If these types of responses to the explicit price signal are sufficiently widespread amongst market participants, it may push back the time at which Transpower has to incur those future costs, potentially resulting in dynamic efficiency benefits. If sending such signals does *not* cause any change in behaviour that delays or downsizes the investment, then that is fine too. It simply reveals that the investment is efficient, and that customers are prepared to pay for it.

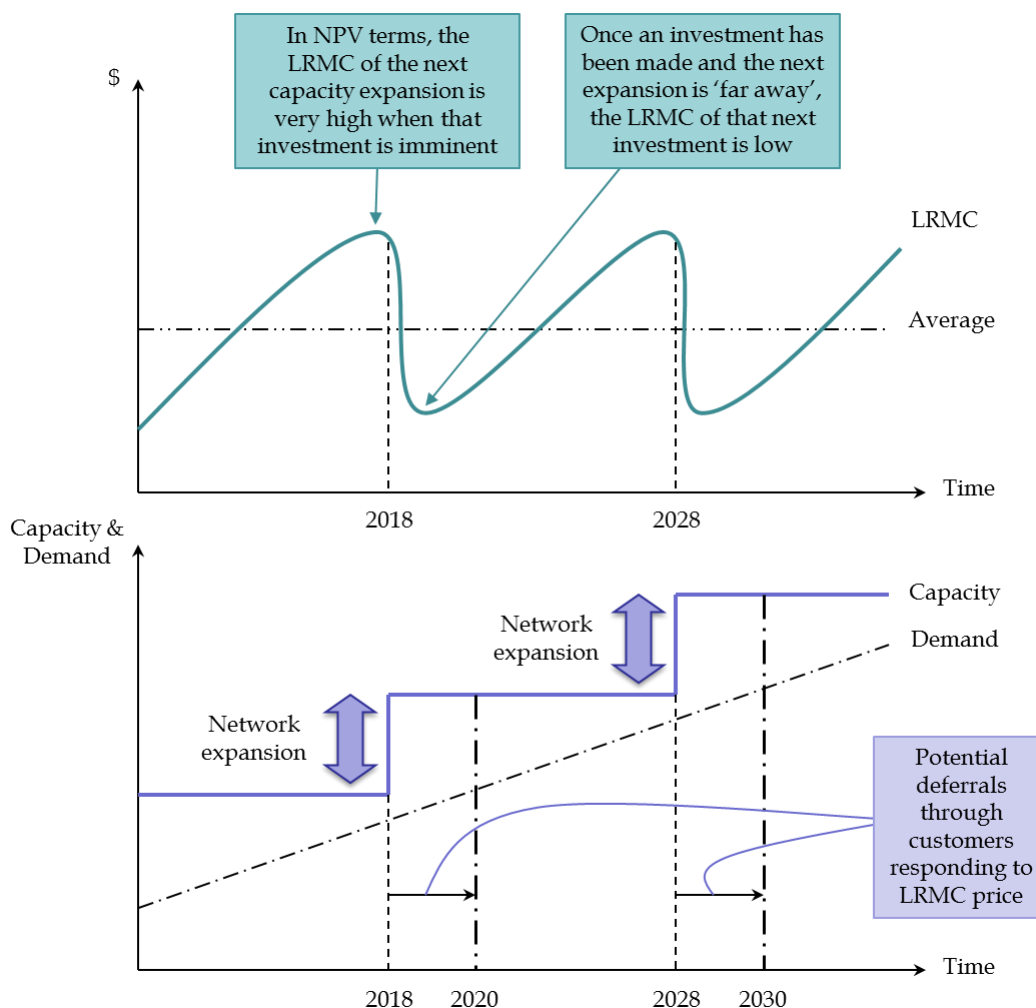
Once the investment has been made, the costs become *sunk*. At that point, an efficient forward-looking price signal should *weaken* to reflect the fact that the *next* investment is now some way off and the net present value of *forward-looking* costs (i.e., LRMC) has dropped. Retaining the strong price signal that existed just *prior* to the most recent investment would only serve to discourage the use of the spare capacity that now exists. Figure 2.2 illustrates.

¹⁶ Although, as we explain in more detail subsequently, in practice, transmission charges are unlikely to have a material bearing on these decisions in the majority of cases.



Figure 2.2: Temporal pattern of LRMC charge

The forward-looking costs of transmission fluctuate over the investment cycle.



Of course, if the forward-looking price is 'reset' to reflect the cost of the *next* investment, it will not produce sufficient revenue to recover the investment costs that have just been sunk. Those fixed sunk costs must therefore be recovered through some other means. The challenge here is not to try and make customers *change* their behaviour in efficient ways, since there is now no point – the investment has been made. Rather, the objective is to recover those sunk costs *without changing* customers' behaviour.

2.1.2 Objective two: efficiently recover sunk costs

If a firm had perfect knowledge about each customer's willingness to pay, the most efficient way to recover the sunk costs of past investments would be to engage in 'perfect first degree price discrimination'. Specifically, the firm could levy a fixed charge on each consumer that reflected accurately its willingness to pay. This would minimise distortions to demand, because:

- no customer would be charged more for existing assets than the private benefits it derives from them, i.e., there would be no inefficient disconnections; and
- the charge is fixed, so customers would not have an incentive to change their behaviour to avoid or reduce the charge.



One might therefore be tempted to conclude that the best way to recover sunk costs is to seek to levy charges on customers in proportion to the private benefits that they derive from those investments, e.g., if a customer is estimated to derive 5 per cent of the total net benefits, it should be required to pay 5 per cent of the fixed costs. However, that is not necessarily so, since it overlooks a number of practical considerations that bear upon the most efficient allocation approach.

To illustrate, imagine that \$100 in sunk costs is being allocated evenly across 100 customers, i.e., \$1 each. Would changing this methodology so as to charge customers in proportion to their perceived levels of private benefits improve static efficiency? It might, or it might not. The answer depends on a number of practical considerations, including:

- the current level of deadweight loss from unserved demand, i.e., the extent to which customers are inefficiently curtailing demand because the \$1 charge exceeds their private benefit;
- the accuracy with which private benefits can be identified – in practice, the firm will not have perfect knowledge of these factors, and if they are overestimated, it might lead to exactly the same distortions – or worse;
- the administrative costs associated with calculating private benefit, i.e., the costs associated with calculating a unique estimate for each customer may be considerable – especially if complex modelling is required; and
- the costs associated with any disputes arising from customers challenging their individual estimates, with a view to receiving lower charges, i.e., customers may claim that their benefits are lower than they have been modelled.

A number of practical factors will influence the most efficient way to allocate sunk costs.

It is conceivable that the distortions arising from the first factor may be quite modest. If sunk costs are spread across a broad customer base, this reduces the probability of the charge exceeding any particular customer's private benefit. The extent of unserved demand may also be quite modest if demand is inelastic. Moreover, the distortions associated with the latter factors might be materially worse.

Attempting to introduce an approach whereby individual customers are allocated costs in proportion to their own estimated private benefit may not therefore produce better outcomes than more pragmatic approaches. There is therefore an important balance to be struck between complexity and practicality, i.e., more complex methodologies do not necessarily promote efficiency – they may even give rise to *more* distortions while needlessly increasing costs.

2.2 The status quo

Under the status quo, an attempt is made to meet the two objectives described above through three *individual* charges: the interconnection charge, the HVDC charge and the connection charge. In each instance, the objective is to send a price signal *and* to recover a fixed amount of revenue to cover the costs of existing assets. We consider each briefly below.



2.2.1 The interconnection charge

The existing RCPD-based interconnection charge exhibits some broadly similar attributes to an LRMC charge. The RCPD charge provides a signal to load customers to reduce their demand during peaks. A customer facing the RCPD charge will consider whether there is anything that it can do to reduce demand – such as invest in distributed generation – that will cost it less than what it is likely to pay if it does not respond. If there is, then:

- the customer will rationally seek to avoid the charge (e.g., by investing in distributed generation or demand-side management), confident that it will be financially beneficial for it to do so; and
- if that type of response is sufficiently widespread amongst market participants, it may push back the time at which Transpower has to incur those future costs, resulting in broader market benefits.

Furthermore, as we explained in our report in response to the previous Options Paper, in a similar manner to an LRMC charge, the ‘strength’ of the signal to curtail demand can be adjusted by changing the number of periods over which the contributions to RCPD is measured, for example:

- when RCPD is approaching the available grid capacity (e.g., just before the investment is made in and LRMC is ‘high’), a small number of periods might be used (e.g., 10 or 12) to encourage load shedding; but
- when RCPD is significantly less than available capacity (e.g., straight after the investment is made in Figure 2.2 and LRMC is ‘low’), a larger number of periods could be used (e.g., 1,000 or 5,000) to dampen the signal to curtail demand.

The RCPD-based charge provides an explicit forward-looking price signal and seeks to recover a fixed sum of sunk costs – but it has limitations.

However, the charge does have some significant limitations. First, the charge does not provide customers with a signal that reflects Transpower’s *forward-looking* LRMC. Rather, it signals to customers that, if they do not curtail demand, they risk paying a larger share of the sunk costs of *existing* interconnection assets. To be sure, there may be strong correlation between the RCPD signal and LRMC, but they will not necessarily be the same.

Second, because the charge must recover a fixed amount of revenue – i.e., to fund Transpower’s interconnection assets – customer’s individual charges cannot be worked out until *after* they have consumed the relevant interconnection service. In other words, although the RCPD charge definitely provides customers with incentives to curtail demand,¹⁷ customers do not know the prices that they will ultimately pay (although, in practice, they may have a reasonably good idea).

Third, the price signal is also provided at a relatively aggregated level – which is not necessarily a bad thing (since it reduces administrative costs, *vis-à-vis* having a larger number of prices), but it does nevertheless limit Transpower’s ability to signal *infra-regional* constraints. Moreover, the only ‘lever’ at Transpower’s disposal to

¹⁷ Under the RCPD charge, it may be a ‘dominant’ strategy for a customer to curtail demand since, if it does not, and others do, it will pay higher interconnection charge.



adjust the strength of the charge is the number of periods over which it is measured. If it does not pull that lever in time, or hard enough, inefficiency can arise.¹⁸

In other words, the interconnection charge seeks to fulfil both limbs of a two-part tariff through a single charge. Namely, by changing the number of periods over which contributions to RCPD are measured, the charge can alter the emphasis that is placed on signalling future investment costs to curtail demand (the ‘first limb’) versus encouraging the use of existing assets (the ‘second limb’). However, there are limits to the extent to which it can achieve both of these outcomes effectively.

2.2.2 The HVDC charge

The HVDC charge is, first and foremost, intended to recover the costs of the existing HVDC assets without distorting the operational decisions of the South Island generators upon whom it is levied (the ‘second-limb’ of an efficient two-part tariff). Historically, that objective has not necessarily been achieved as well as it might have been. Namely, the HAMI-based parameter has provided incentives to South Island generators to withhold generation capacity to avoid HVDC charges.¹⁹

The HVDC charge provides an explicit price signal to generators and seeks to recover a fixed sum of sunk costs – but it also has limitations.

These inefficiencies were recognised by both Transpower and the EA during the recent operational review.²⁰ The HVDC charge will consequently soon start to transition to a ‘South Island mean injection’ (SIMI) charge. Specifically, from 1 April 2017, South Island generator’s HVDC charges will start to reflect their total annual injection into the South Island grid, in MWh terms, averaged over the capacity measurement periods for the previous five pricing years.

In approving the change in methodology, the EA observed that a SIMI-based charge would promote static efficiency for the long-term benefit of consumers, by reducing the incentive of South Island generators to withhold generation capacity.²¹ Importantly, although the SIMI charge will not officially be in place until next year, we understand that customers are already changing their behaviour in response to it, i.e., by offering more capacity. In other words, any static inefficiency historically associated with the HAMI charge has been reduced significantly through the change in charging parameter.

The HVDC charge also provides a forward-looking price signal, of a kind (the ‘first-limb’ of a two-part tariff). Specifically, it provides a signal to generators that the impact on Transpower’s forward-looking transmission costs will be greater if a new generation investment is made in the South Island, rather than the North Island, all other things being equal. In other words, it provides an ‘inter-island’ locational pricing signal.

¹⁸ Indeed, as we explain throughout the remainder of this report, the Issues Paper makes a strong case that the current RCPD signal is too strong, i.e., that it is measured over *too few* periods.

¹⁹ Electricity Authority, *HVDC component of Transpower’s proposed variation to the Transmission Pricing Methodology, Decisions and reasons*, 14 August 2015.op. cit., p.5.

²⁰ *Ibid.*

²¹ *Ibid.*



The work undertaken by Green *et al* (2009) for the CEO Forum, and the subsequent modelling work by Transpower, suggest that it is almost certainly the case that it is costlier, from a transmission pricing perspective, for generators to locate in the South Island than the North Island. However, it does not follow that the existing HVDC charge – which, again, reflects *past* investment costs – will necessarily provide a robust signal of *forward-looking* LRMC. In other words, it is possible that the price signal is currently too strong, or too weak.

2.2.3 The connection charge

Connection charges recover the costs associated with connecting generators or off-take customers to the transmission system.²² As a ‘rule of thumb’, connection assets are those that would not exist were it not for the existence of identifiable customers, i.e., if those customers were not there, then the assets would also not be there.²³ Connection charges are levied on those customers that are connected to the relevant assets,²⁴ and they are only applied *after* the investment costs have been incurred.

As the Issues Paper explains, although connecting parties are only charged for connection investments *after* they occur under the TPM, they know that they will have to pay the full costs of expanding the connection capacity serving them.²⁵ Moreover, they may have a relatively good understanding of the likely magnitude of those costs, and will often be the only one paying them. And, by definition, those prices will reflect Transpower’s LRMC.

It follows that, even though the TPM does not send an explicit price signal to customers *before* connection investments are made, this does not mean that customers are unaware of the consequences of their actions on Transpower’s future costs, or are unable to respond. Moreover, the connection charging regime provides little incentive for parties to change their behaviour *after* a connection investment has been made since, in most cases, those costs are unavoidable.

In other words, as the Issues Paper highlights, the connection charging regime provides parties with a relatively efficient *implicit shadow price signal*.²⁶ That single price appears to do a good job of achieving *both* elements of an efficient two-part tariff, i.e., it provides a relatively efficient ‘shadow price’ that signals implicitly

The connection charge provides a relatively efficient implicit ‘shadow price’ signal to connecting customers.

²² A connection asset is any asset at a defined connection node and any asset at a defined interconnection node that is specifically required to connect a customer to the transmission grid, plus any connection link that has a connection node at one or more of its ends.

²³ In other words, if the beneficiaries of particular assets cannot be identified (e.g., if there is a ‘completed loop’ and therefore loop flows and parallel flows are possible) then the asset is unlikely to be a connection asset.

²⁴ If there is only one customer in a connection location (i.e., if the assets are ‘dedicated’ connection assets), then the costs attributable to that location will be funded primarily by that customer. However, if there are multiple connecting customers at a connection location (i.e., if the assets are ‘shared’ connection assets), then the costs are allocated to those customers based on their anytime maximum demand (AMD) or injection (AMI).

²⁵ Issues Paper, §5.43.

²⁶ Issues Paper, §5.43.



Transpower's future costs, and it recovers sunk connection costs without giving rise to material distortions in demand.

2.3 The proposed AoB charge

The Issues Paper concludes that while the connection charging regime described above is reasonably efficient, the interconnection and HVDC charges are not. The basic proposition is that the *forward-looking* price signals provided by these two charges are poor, i.e., they do not meet the first objective of efficient transmission pricing described in 2.1.1. In particular, the Issues Paper contends that:

- the RCPD-based interconnection charge is currently *too strong*, and is incentivising load customers to curtail demand (e.g., through distributed generation) to avoid transmission charges even though this may not be avoiding long-run transmission costs, i.e., because there is plenty of spare capacity;
- in the longer-term, any shortcomings in the price signals provided through the RCPD and HVDC charges that resulted in inefficient grid usage could, in turn, lead to inefficient grid investments, since the Commerce Commission (Commission) might take current/forecast usage 'as given' when approving new expenditure; and
- generators can make investment without having to take into account the impacts on interconnection costs, which may result in poor outcomes – and the paper seems to imply that the HVDC charge may currently be too strong, since it is allocated fully to South Island generators, when North Island load also benefits.

The Issues Paper claims that the interconnection and HVDC charges send poor price signals that lead to inefficient outcomes.

These 'poor' price signals are said to incentivise inefficient use of the interconnected grid and inefficient investment by Transpower and grid users. They are also claimed to compromise participation in the investment approval processes, e.g., if parties do not have to pay for assets from which they benefit they may support inefficient investments. Finally, the status quo is said not to be durable, with significant resources directed at lobbying for fundamental change.

The chief recommendation in the Issues Paper is to replace the interconnection and HVDC charges with an AoB charge and a residual charge – with the former assuming more prominence over time, as more assets come under its ambit. Importantly, neither of these charges would send an *explicit* price signal to customers of Transpower's long-run costs. Rather, the proposal would remove the only two components of the TPM which currently do so:

- it would remove the RCPD charge which, as section 2.2.1 explained, enables Transpower to provide signals to load customers to curtail or increase demand, as the case may be, by changing the number of periods over which the contributions to RCPD is measured; and
- it would remove the HVDC charge which, as section 2.2.2 highlighted, provides a signal to generators that the impact on Transpower's forward-looking transmission costs will be greater if a new generation investment is made in the South Island, rather than the North Island.

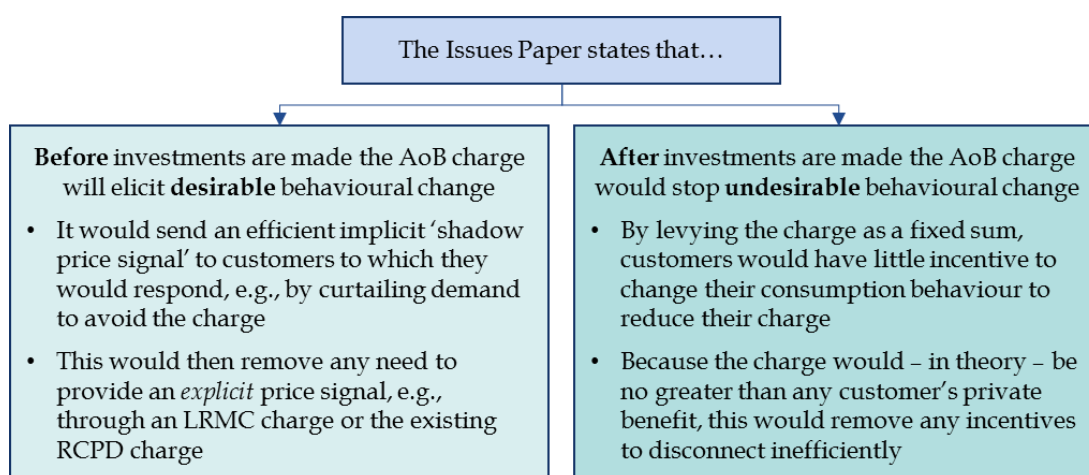


The Issues Paper implies that each of these charges is inefficient – and that it is not necessary to send an *explicit* price signal in any event. Rather, the Issues Paper suggests that it is preferable to approach the same ‘shadow pricing’ approach that is currently applied to *connection assets* to *interconnection assets*. In other words, there is said to be no need to provide any form of explicit *ex-ante* price signal to promote dynamic efficiency. Instead, the Issues Paper states that:

- the prospect of paying AoB charges in the *future* would be sufficient to motivate efficient consumption and investment decisions from generation and load customers *today*, i.e., it would efficiently signal future costs; and
- because the charges would be levied as fixed annual sums, customers would have no incentives to change their behaviour to avoid them once an investment has been made, i.e., it would efficiently recover sunk costs.

In other words, the basic proposition in the Issues Paper is that the AoB methodology (supplemented by a residual charge²⁷) would deliver *both* of the core aspects of an efficient two-part tariff, through a single charge. Moreover, it would do so more efficiently than the interconnection and HVDC charges, even though it would only be sending an *implicit* shadow price signal. Figure 2.3 illustrates.

Figure 2.3: Theory underpinning the proposed AoB charge



In our view, the AoB would not achieve either of these objectives as it is currently framed in the draft Guideline. The charge could not elicit desirable behavioural change because the implicit ‘shadow price’ signal would be inefficient. And the extent to which it could give rise to a less distortionary allocation of sunk costs would depend upon many factors, including the way in which private benefits were estimated. We explain why in the following sections.

²⁷ We note that there would be an ongoing need for a residual charge, but the key objective of the AoB charge is to provide both an efficient forward-looking price signal and a non-distortionary allocation of sunk costs.



3. Would the AoB charge provide an efficient forward-looking price signal?

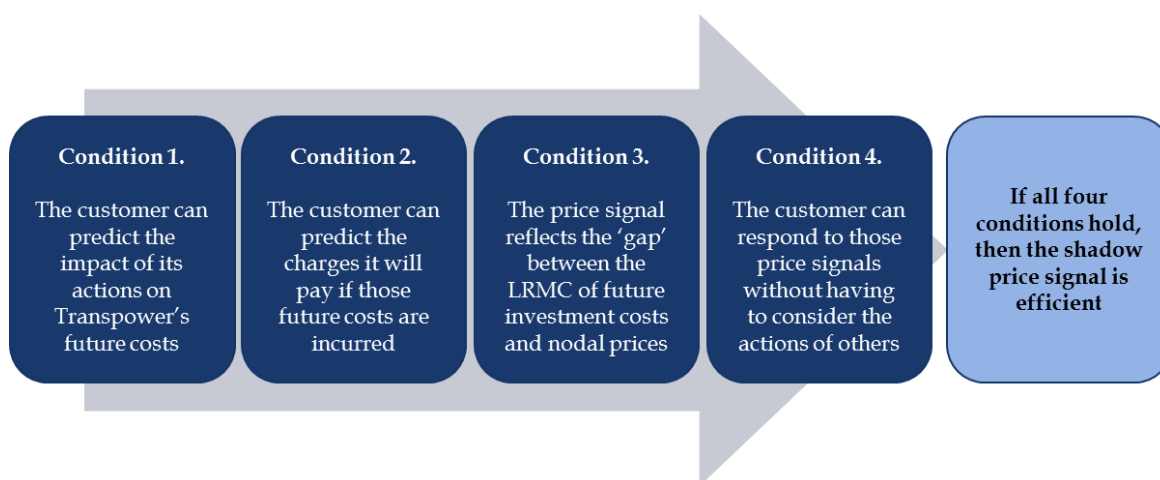
In this section we explain why the implicit ‘shadow price’ provided by the AoB charge would not provide an efficient, or predictable, signal to grid users of the consequences of their decisions on Transpower’s future costs. Several key conditions must be in place before a shadow price can send an efficient forward-looking price signal. As we explain in the following section, none of these conditions hold in the case of interconnection assets.

3.1 The conditions for an efficient shadow price

A shadow price can only provide an efficient price signal if four conditions hold.

The Issues Paper states that an explicit *ex-ante* price signal may not be needed to promote dynamic efficiency. The logic, as we understand it, is that the prospect of paying higher transmission charges in the future may be sufficient in itself to motivate efficient consumption and investment responses from both generation and load i.e. that the expectation of paying AoB charges creates a ‘shadow price’. However, a shadow price can only provide an efficient price signal if four critical conditions hold, which are summarised in Figure 3.1.

Figure 3.1: Conditions for an efficient implicit shadow price



These conditions could well hold for dedicated connection assets, but they do not hold for interconnection investments.

We consider that these four conditions are only likely to hold, at best, in relation to connection assets. As the Issues Paper explains,²⁸ and as we foreshadowed in section 2.2.3, although connecting parties are only charged for connection investments *after* they occur under the TPM, they know that they will have to pay the full costs of expanding the connection capacity serving them. They may also have a good understanding of the connection prices they will pay and, if they are the only connecting party, those prices will reflect LRMC.

²⁸ Issues Paper, §5.43.



However, the Issues Paper suggests that these conditions would also be met in relation to shared, *interconnection* (and HVDC) assets.²⁹ We infer from the Issues Paper that the ‘shadow price’ is expected to work in broadly the following way:

- when there is spare capacity throughout much of the grid (i.e., LRMC is low) a party would know that if it did not curtail demand during peak periods, this would not cause Transpower to have to invest any time soon and then charge that party under the AoB charge framework, i.e., the charge would incentivise consumption when there is spare capacity; but
- once constraints start to emerge (signalled through escalating nodal prices), a party would know that if it increased consumption during peak periods this might increase the chance of Transpower having to invest and that party (and perhaps others) then having to pay under the AoB charge framework, which would provide it with an incentive to curtail demand when there is a more imminent need to invest.

In our opinion, there is little or no likelihood that the four key conditions set out above would hold in relation to shared interconnection assets. We also consider that it is very unlikely that customers would respond to ‘shadow prices’ in the same way that they would respond to an explicit price signal, such as an LRMC charge. The proposed AoB charge consequently should not be relied on to ‘address the gap’ that exists between nodal prices and LRMC. We expand further below.

3.2 Customers would not be able to predict Transpower’s future costs

For the AoB charge to send an efficient price signal, customers would first have to be able to draw a direct and accurate link between actions they take today and interconnection costs that Transpower would incur in the future.³⁰ Customers would have to rely on (imperfect) information provided in Transpower’s planning and investment documents and attempt to infer the relationship between their own actions and the need for (and timing of) future transmission investments.

It is highly unlikely that such a clear or straightforward link would exist, or for customers to infer any such associations with any accuracy. There are many factors which drive transmission investment needs, much or most of which would not be readily ascertainable by all customers, and many of which would be either partly or wholly beyond their control.

Customers would not be able to draw a clear link between actions they take today, and the effects on Transpower’s future costs.

²⁹ Perhaps the clearest explanation of this ‘implicit shadow price’ phenomenon is contained in the Oakley Greenwood report. See: OGW CBA, p.23.

³⁰ As we explained in section 2, with an *explicit* price signal, such inferences are unnecessary. The price itself signals to the customer when its actions are likely to impact upon future costs.



The EA found that customers would not be able to make such predictions in its distributed generation Consultation Paper.

We note that the EA considers this condition would not hold in its parallel consultation process on the pricing principles for distributed generation, for these very reasons. In that context, the EA stated:³¹

- the TPM would provide for an AoB charge and a capacity-based residual and each EDB would 'look ahead' to identify potential transmission investments they would use or benefit from, and hence pay for if they went ahead; and
- the EDB would consider contracting for investment in, and operation of, distributed generation to defer the need for these potential transmission investments, which would defer the increase in the EDB's transmission charges.

However, the EA dismissed this as a viable process because it did not consider that EDBs and distributed generators would be able to draw a sufficiently clear link between their actions, the future transmission costs that Transpower would incur, and the future charges they would pay. Specifically, it concluded that:³²

'...there would be a significant impediment to distributors and owners of distributed generation agreeing to such contracts. This is because they are unlikely to have the full information needed to determine what transmission investments might be required, and how the operation of distributed generation could defer the investment.

One consequence of this lack of information would be that distributors could not be confident that Transpower would actually defer the transmission investment(s) as a result of the operation of the distributed generation.'

In our opinion, the position that is expressed in the distributed generation paper represents a more realistic assessment of the extent to which parties could feasibly predict future costs. Other customers would face exactly the same challenges as distributed generators and EDBs.

Transpower could certainly help by providing regular updates to customers on its future investment programmes. As part of that process it might even seek to identify what was driving those investment needs, and steps that might be taken to defer those costs. However, this still would remain an imperfect substitute for providing a proper *ex-ante* price signal.³³

3.3 Customers would not be able to predict future charges

The second key condition is that customers must be able to predict the AoB charges that they will eventually have to pay if they make certain consumption or

³¹ Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.

³² Electricity Authority, *Review of distributed generation pricing principles, Consultation Paper*, 17 May 2016, Appendix E.2-E.3.

³³ For one thing, all customers would see an *ex-ante* price, whereas not all would read and understand a planning document, let alone fully comprehend the links between their individual consumption and investment decisions and Transpower's future investment requirements.



investment decisions. The proposed design of the AoB charging methodology is likely to make that very difficult. The Issues Paper contemplates Transpower allocating costs to beneficiaries in areas of benefit *once and for all* when an investment is made. This would require it to:

- allocate costs to parties in those locations over the entire expected lives of the assets in question – which could be as much as 50-years; and
- take into account any number of potential uncertainties, such expected future load growth, the timing and location of future generation investments, etc.

In our opinion there could be considerable uncertainty surrounding those future charges and it would be impossible for Transpower to undertake this exercise with any real degree of accuracy (we explain further in section 5.3). Any such allocation would be heavily assumption-driven and, inevitably, highly controversial. It would consequently be very difficult for a party to predict accurately how Transpower might set future prices.

Customers would not be a position to assess the future AoB charges they would face if they took certain actions.

However, the challenge for the customer does not end there. It would need to assess what its future AoB would be under (at least) *two* states of the world – one in which it takes a certain action – such as installing distributed generation to curtail demand (the ‘factual’) - and one in which it does not (the ‘counterfactual’). This would require it to make an accurate evaluation of:

- when the investment will occur and the total size of that investment cost under the ‘counterfactual’ (i.e., if the customer does not ‘act’ by, say, installing distributed generation);
- the portion of that total investment cost that will be assigned to its ‘area of benefit’ – and its share of that cost (e.g., based on its estimated share of private benefits – which would require information on its own net benefits, and *other parties’* net benefits) under the ‘counterfactual’; and
- how all of those variables would change if the customer takes the relevant action under the ‘factual’ (e.g., installs distributed generation), i.e., how that affects the timing or size of the investment and its assessed share of benefit.

In our opinion, it is highly unlikely that customers would be in a position to make informed assessments on any or all of these matters. Interconnection investments are driven by a variety of factors for which there will be a wide nexus of benefits. Most customers are therefore likely to have only a vague notion of what their future charges might entail under the various ‘states of the world’.

3.4 Customers’ future prices would not reflect LRMC

The third key condition for an efficient shadow price is for the price signals – and eventual charges – to reflect the ‘gap’ between nodal prices and LRMC. In this respect, it is important to recognise that, while LRMC may fluctuate over time (as illustrated in 2.1.1), at any point in time, it is a single, unique number. Although that LRMC number may differ depending on the methodology with which it is calculated, it is entirely agnostic when it comes to *particular customers*.



For example, the fact that ‘customer A’ might derive, say, twice the ‘private benefits’ of ‘customer B’ from a forecast new investment would not affect the size of the price signal that they would face under an explicit LRMC charge. It would be *the same* for both customers, irrespective of their projected ‘future private benefits’. A response by a party that is likely to benefit significantly from a future investment is not ‘worth more’ than an equivalent response by a party that benefits less, i.e., it does not defer more costs.

The shadow price that each customer perceived would not reflect the LRMC of transmission.

For example, 100kVA of load reduction from a customer that would derive, say, 90 per cent of the private benefits of a new investment would not deliver a greater reduction in long-run costs than 100kVA of demand curtailment from a customer that would derive only, say, 10 per cent. The “marginal cost of the next investment” is the aggregated sum of *all* prospective AoB charges – and each customer only faces a different fraction of that total (depending upon their perceived ‘share’ of private benefits), instead of each facing the same cost-reflective charge.

The design of the AoB charge would mean there was an array of *multiple* implicit shadow prices for each future investment – each of which reflected an individual customer’s perceived share of private benefits. For example, if two customers saw that there was a \$100m investment on the horizon, the implicit shadow price that they perceived might be quite different, for example:

- if customer A thinks it will be assessed as receiving 80 per cent of the private benefits, it will anticipate paying \$80m in AoB charges over the life of the asset and make decisions on the basis of avoiding that quantum; and
- if customer B estimates that it will be assessed as receiving 20 per cent of the benefits, it will expect to pay AoB charges totalling \$20m over the life of the asset and make decisions on the basis of avoiding that smaller sum.

In this simple example, the implicit price signal perceived by customer A is *four times as strong* as that perceived by customer B. Moreover, as we have already seen, those signals may bear no resemblance at all to the LRMC associated with each customer’s actions which, as we described above, would be the same. Specifically, both of those customers may be equally well-placed to take steps to reduce those future costs (e.g., to engage in demand response), yet the charge would provide completely different signals.³⁴

This is inconsistent with orthodox practice under an explicit *ex-ante* price, where such charges are typically levied on the *same basis* for all customers. For example, an LRMC charge (\$/kW) levied on all load customers that consume during specified peak demand periods would be the same rate for *all* customers. Although the *total bill* that each customer ultimately paid would vary – based on the amount that each consumed during the relevant periods – they would still all face the same explicit price signal.

³⁴ Furthermore, for the reasons we set out in the previous section, the AoB charges that customers A and B expect to pay (the ‘shadow price’) may bear very little resemblance to the prices they ultimately end up paying.



We therefore conclude that private benefits have *no role* to play in the design of an efficient forward-looking price signal. Specifically, there is no basis to presume that signalling to a customer that it will pay a future price that reflects its share of private benefits will give rise to efficient consumption and investment decisions. That requires a price signal which reflects some measure of *forward-looking costs*, such as LRMC. As we explained above, forward-looking costs are not influenced by relative *private benefits*.

3.5 The actions of others may affect customers' choices

Even if AoB charges did reflect the LRMC to Transpower associated with each customer's actions and those prices could be perfectly predicted, they would not necessarily have an incentive to make efficient consumption and investment decisions. This is because the customer would need to take account of the potential actions of *other customers*.

Any customer that sought to, say, curtail demand with a view to deferring a future transmission investment for which they expected to be allocated an AoB charge, would incur higher costs in the near-term. This is because it would either have to switch to more expensive sources of supply – such as distributed generation – or reduce demand (which also entails an opportunity cost). In contrast, the attainment of a future private benefit could depend upon the actions of others, since:

- if other parties also curtailed their demand, then the transmission investment might be deferred – giving rise to private benefits in the long-term that might outweigh the higher costs the customer incurred in the near-term; but
- if the customer curtailed its demand, but others did not, then the transmission investment *might not* end up being deferred – in which case it would have needlessly incurred costs without obtaining any significant long-term benefit.

Customers may rationally choose not to take efficient actions, since the benefits they receive from doing so may depend on the actions of others.

When faced with the choice of continuing to use the grid in the same way, or switching to a more-costly substitute that may defer an investment if others do the same, a customer might rationally conclude that it is not worth the risk. Put simply, the prospect of receiving an uncertain benefit at some point in the future which depends on how others behave, may not justify incurring a near-term cost with certainty. By way of simple example (using round numbers):

- a customer might assess that if it spent \$100 embedding generation – and that others did also – that this could defer transmission costs and provide it with a private benefit of \$200; but
- before the customer would be willing to spend the \$100 it would first need to be confident that there was a greater than 50 per cent chance that other customers were going to respond in kind; because
- if the probability of others responding in kind was less than 50 per cent, then the expected value of the future private benefit would be less than the near term cost it would incur embedding generation, i.e., $\$100 \times 100\% > \$200 \times 49\%$.



This could result in what is known in economics as a ‘tragedy of the commons’. Specifically, the design of the AoB charge could result in customers behaving quite rationally in their own self-interest, yet in a way that may be contrary to the common good of all users. An analogy to consider is a bridge into a central business district that was becoming heavily congested during rush hours, causing residents to face the prospect of higher rate bills to fund the addition of new lanes.

Even if a motorist realised that she was contributing to the congestion problem and that she would pay higher rates if the bridge was widened, that does not mean that she would stop using the bridge during rush hours. She might determine that her own actions would make no difference and that, even if she did decide to delay her commute or use an alternative route that other motorists would not, which would render any efforts on her part obsolete. If enough motorists thought in this way, then a tragedy of the commons could arise.³⁵

3.6 Effect of the ‘marginal benefit adjustment mechanism’

The Issues Paper also contemplates a special case in which a customer is able to respond to what is termed a ‘marginal price signal’. The paper describes a very specific scenario in which Transpower publishes an ‘investment proposal’ and customers then have an opportunity to respond.³⁶ The assumption appears to be that any such document would:

- describe the proposed investment in some detail;
- provide precise details of the AoB charges that all relevant customers would be paying if the investment was to proceed;
- be provided to all of those affected customers; and
- be provided some period before the investment was scheduled to take place.

The marginal benefit adjustment mechanism cannot be relied upon to solve the above problems and would create others.

The basic idea of the proposed mechanism is that, upon receiving the news that an investment is about to occur, one or more of the affected customers might offer to credibly commit to taking steps that would either defer or downsize the size of that transmission investment. Those customers would then receive the benefit of reduced AoB charges when the investment eventually does take place.

The hypothetical example in the Issues Paper involves a customer undertaking to invest in distributed generation, thereby allowing Transpower to install a smaller, cheaper transformer than what it had initially announced in its investment proposal. The customer in question then receives a benefit once the (now smaller)

³⁵ An alternative approach would be to signal the future costs of the ‘bridge widening’ project through an explicit congestion charge levied on motorists that elected to drive over the bridge during rush hours. Once faced with such a price, each road user could then decide whether the private benefits they derived from travelling that route at that time outweighed the costs and, if necessary, change behaviour in socially beneficial ways. Those decisions would not be affected by the actions of others – it would simply be a question of whether a customer thought it was worth paying the toll or not.

³⁶ Issues Paper, p.105.



investment occurs by paying an AoB charge that reflects the marginal cost saving it has allowed Transpower to achieve *vis-à-vis* its original investment plan.³⁷

The basic objective of this mechanism appears to be to replicate the outcomes that would arise under a conventional explicit *ex-ante* price signal, which we described in section 2. Except, instead of providing a price signal that has immediate financial repercussions (such as an LRMC charge), Transpower effectively supplies each customer an indicative future bill and says “this is what you will have to pay, unless something changes.”

In the hypothetical example set out above, one customer ‘reveals’ that it has a cheaper alternative (i.e., investing in distributed generation), and this results in an efficient downsizing in the investment. However, there are a number of problems with the proposed mechanism. Many of these challenges only become clear once one steps away from the simple example set out in the Issues Paper into some of the more complex scenarios that would arise in practice.

First, the ‘marginal price signal’ contemplated in the Issues Paper would only be providing an explicit price signal at *one point in time*, i.e., once Transpower presents customers with ‘indicative future bills’ in an ‘investment proposal’. Unlike, say, an LRMC charge (which can fluctuate over time), that signal will only be one strength – presumably ‘very strong’, assuming that ‘investment proposals’ relate only to investments to be made relatively soon.³⁸

The marginal price signal would be unsophisticated and would not prevent ‘tragedies of the commons’.

Second, the mechanism would not address the problems associated with ‘tragedies of the commons’ described in the previous section. In the hypothetical example set out in the Issues Paper a *single party* is able to credibly commit to reduce its demand by an amount sufficient to downsize the investment. Specifically, a transmission cost saving is made when one customer reduces its peak load to 100kVA. But imagine instead that no single customer could reduce their peak load by this much – but that the five customers could each curtail peak demand by 20kVA; that is:

- no customer *in isolation* can credibly commit to curtail enough demand to downsize the investment, i.e., none can reduce peak load by 100kVA; but
- all customers acting *in aggregate* could credibly commit to delivering the 100kVA peak load reduction that is required, i.e., 20kVA x 5 customers.

³⁷ Presumably an analogous situation would arise if Transpower were to have built the same sized transformer, but a year later, i.e., the marginal saving would reflect the NPV of the deferral of that capital investment.

³⁸ This point is unclear, but the mechanism is unlikely to be practicable for longer-term investments. This is because a party only receives a reward once an investment has been made, i.e., it is compensated through paying a lower AoB charge than it would otherwise have paid. If Transpower released an ‘investment proposal’ that said that it was going to build a new asset in, say, 3 years’ time, parties may be disinclined to, say, credibly commit to invest in distributed generation to defer that investment. The simple reason is that many things could happen in the ensuing period before the investment is made that could serve to compromise that pay-off, e.g., a major new load could connect and bring the investment need forward. These intervening events would also make it very difficult – if not impossible – for Transpower to administer the scheme, i.e., to keep track of the prices that each party should be paying.



If the customers do not coordinate, then a tragedy of the commons would arise – something that would *not* occur if an explicit price signal was provided. The only way in which the efficient outcome could be achieved under the proposed discount mechanism is if the five customers cooperated in some way – either independently or, potentially, through a third-party aggregator – so that they can offer Transpower ‘the whole 100kVA’ that it needs.

It might sometimes be possible to form such a coalition, and sometimes the difficulties associated with coordinating between multiple parties may prevent such outcomes from eventuating. Moreover, even when such coordination does occur and transmission costs are avoided, the transaction costs that would be incurred in achieving those benefits are likely to be considerably greater than under a scenario in which an orthodox, explicit price signal had been provided.

The mechanism could still result in customers paying for investments from which they derive no benefits.

Third, the application of the mechanism could result in counterintuitive outcomes. For example, it could result in customers paying for a share of investments from which they derive no private benefits. To illustrate, imagine that customer in the hypothetical example in the Issues Paper invested in distributed generation that eliminates its 200kVA peak load, i.e., its demand during peak periods is zero. But imagine that its demand during off-peak periods – where nodal prices are lower – is still positive.

Under the scenario postulated in the Issues Paper, Transpower would only have to install an 800kVA transformer, and its investment cost would fall from \$2,000 ($\$1,000 + 1,000 \times \$1/\text{kVA}$) to \$1,800 ($\$1,000 + 800 \times \$1/\text{kVA}$). The customer that invested in distributed generation would receive no benefits at all from the transformer upgrade, since users are assumed to benefit in proportion to their peak usage and the customer has zero peak demand.

Yet despite receiving no benefit at all from the upgrade, the customer that curtailed demand would still have to pay an AoB charge. Specifically, it would pay a charge equal to \$200 for its 0kVA of peak demand, i.e., \$400 for the 200kVA it was allocated under the initial investment, less $200\text{kVA} \times \$1/\text{kVA}$ for eliminating all of its peak demand). In other words, if one of the objectives of this mechanism is to produce prices that reflect private benefits, it will not necessarily achieve that outcome.

The mechanism would complicate Transpower’s investment planning framework, giving rise to additional costs.

Finally, the mechanism could complicate considerably Transpower’s investment process. That planning process could be side-tracked by the receipt of an application from any party which would, presumably, cause Transpower to put the project on hold. It may also find itself considering multiple applications that may have different merits. More generally, it would require:

- Transpower to provide estimates of the private benefits it expects each party to receive from a grid upgrade proposal, along with estimates of private benefits arising under alternative options; and
- the TPM to allow Transpower to make pricing adjustments on the basis of estimated shares of benefits of transmission upgrades (and proposed investment costs) that have not been approved by the Commission.

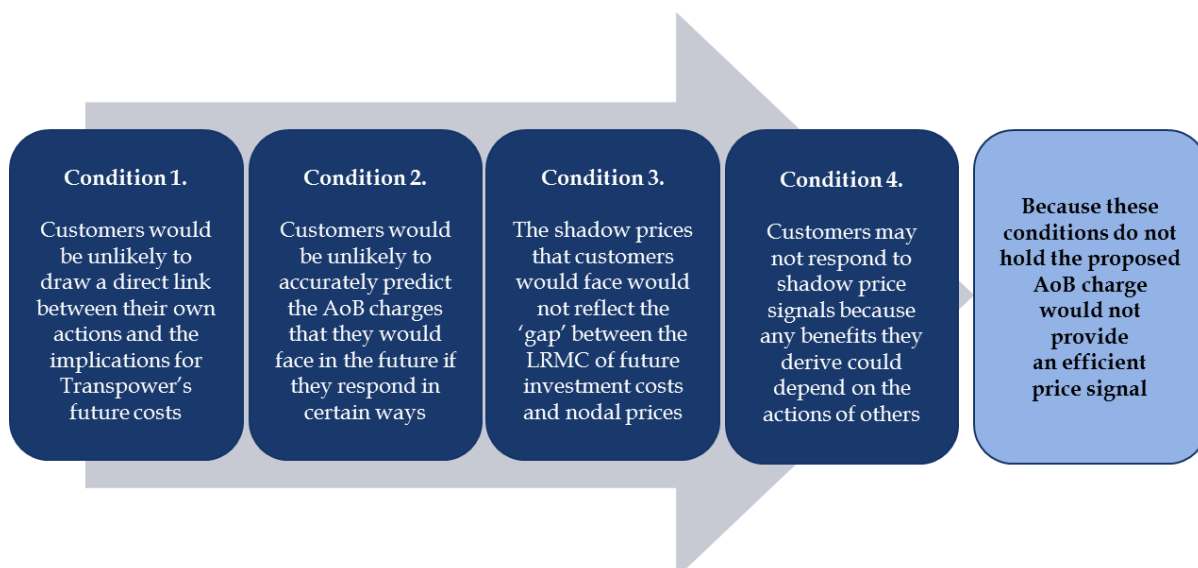


There is also the practical question of what would happen if, say, Transpower had offered a marginal discount to a customer based on its belief that it could build a smaller asset, but the Commission did not subsequently approve that upgrade (or the proposed investment costs). The customer would have incurred costs (e.g., investing in distributed generation) on the assumption that it would receive a future benefit that was ultimately not forthcoming.

3.7 Summary

The four key conditions that must apply for a shadow price to send efficient signals to customers could well hold in the case of dedicated connection assets, where further investment needs are typically quite clear, and where it is usually the actions of one party – i.e., the connecting customer – that is driving those investment needs. However, those conditions do not hold for investments in interconnection assets, as Figure 3.2 illustrates.³⁹

Figure 3.2: The conditions for an efficient shadow price do not hold



The AoB charge therefore would not provide customers with the right incentives to make efficient consumption and investment decisions. In the following section we explain how the charge as proposed could have gave significant adverse implications for both short- and long-term efficiency.

³⁹ Recall that the 'marginal benefit adjustment mechanism' cannot be relied upon to address the problems identified in Figure 3.2. In particular, it would not avoid the possibility of a 'tragedy of the commons'. It would introduce other significant problems, such as disrupting Transpower's investment planning and processes.



4. Impacts of the inefficient price signal on consumption and investment decisions

In this section we consider how the shadow price signals provided by the AoB charge might affect the consumption and investment decisions of load and generation customers. We also consider whether introducing the proposed methodology would be likely to give rise to more constructive engagement in grid investment decision processes.

4.1 Effects on decisions by load

The Issues Paper states that one of the principal problems with the interconnection and HVDC charges is that they provide poor *ex-ante* price signals, which incentivise inefficient use of the interconnected grid. In particular, the RCPD-based charge is said to incentivise load shedding (e.g., through distributed generation), even though there is now significant spare transmission capacity throughout much of the grid (the OGW CBA estimates there will be \$90m in benefits from addressing this matter over its 20-year assessment period).⁴⁰

The Issues Paper suggests that the shadow price signals would lead to efficient consumption and investment by load customers.

The proposed AoB charge is said to address these potential problems through the ‘shadow price’ described above. As we noted in the previous section, the theory underpinning the charge is that, when there is spare capacity, customers will be encouraged to use the grid because the shadow price signal would be relatively weak. But, as the time for new investment approaches, the signal will strengthen, incentivising demand curtailment. In other words, it is said that the shadow price would result in load making efficient consumption decisions through time.

The Issues Paper also claims that any such improvements in the efficiency of consumption decisions would, in time, result in more efficient investment decisions by both Transpower and load customers. In particular, the Commission would not be put in position where it approved an investment that could have been avoided through efficient demand curtailment. In our opinion, the AoB charge is unlikely to offer these advantages, in practice. Instead, it risks incentivising inefficient consumption and investment decisions by load.

4.1.1 Effects on usage when there is spare capacity

We agree that the proposed reform would remove any incentive that load customers might otherwise have to reduce their use of the transmission grid during peak periods when there is spare capacity. However, this outcome would not be achieved through the introduction of the AoB charge. In our opinion, any such outcome would be more appropriately attributable to the *removal* of the existing *ex-ante* price signals from the TPM – namely, the signal currently being provided through the RCPD-based interconnection charge.

⁴⁰ However, as we explain in more detail in section 7, the figure itself rests on some assumptions about the future penetration of embedded diesel generation that appear not to be plausible.



Removing the RCPD charge would stop inefficient load shedding, not introducing the AoB charge.

If the proposal was implemented, load customers would not stop trying to reduce consumption in the 100 RCPD periods because they were implicitly assigning a very low ‘shadow price’ to the *future* AoB charges that they might have to pay. They would do so because there would no longer be any financial benefit from curtailing demand if the RCPD-based price was no longer there. Any benefits would therefore stem from having *no* peak-demand-based price signal – not because of the introduction of a new shadow price.⁴¹ The same benefits could be obtained by:⁴²

- allocating costs purely at random and applying a lump-sum tax;
- removing the AoB charge from the proposed methodology and retaining the capacity-based residual charge on load;
- replacing the AoB charge with an LRMC-based charge and retaining the capacity-based residual charge on load; or
- increasing substantially the number of periods over which the RCPD charge is measured, e.g., from 100 to, say, 1,000 or 5,000.

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

4.1.2 Effects on usage when capacity is constrained

One of the advantages of the existing RCPD-based interconnection charge (or an LRMC charge – see section 2.1.1) is that it enables Transpower to send a signal – albeit an imperfect one⁴³ – to customers to curtail their consumption during times of coincident peak demand as capacity constraints start to emerge in a region. For example, by reducing the number of periods over which RCPD is measured – from 100 to, say, 12 – customers can be provided with a strong incentive to manage their loads during that relatively small number of periods.

As we explained in section 2.2.1, it is relatively straightforward to see how the current RCPD-based charge could result in more efficient grid usage in these circumstances. Specifically, a customer would ask itself: “is there something that I could do to reduce demand – such as invest in distributed generation – that would

Removing the RCPD charge would prevent Transpower from efficiently signalling future constraints.

⁴¹ It is consequently inaccurate for the OGW CBA to characterise the \$90m said to flow from the ‘replacement of the RCPD charge’ as a benefit of *the AoB charge*. Any benefits would instead be more reasonably attributable to the fact that there is currently spare capacity throughout much of the grid which means that, right now, it may be better to send *no ex ante price signal at all*, since the LRMC of future transmission costs is generally quite low.

⁴² In all of these cases, parties would have little or no incentive to reduce consumption during peak periods to specifically avoid transmission charges which, given the current point in time in the investment cycle, could well deliver a positive net benefit.

⁴³ Section 2.2.1 described some of the limitations in the RCPD charge.



cost me less than what I am likely to pay under the interconnection charge if I do not respond?” If the answer to that question is ‘yes’, then:

- the customer will rationally seek to avoid the charge (e.g., by investing in distributed generation or demand-side management), confident that it will be financially beneficial for it to do so; and
- if that type of response is sufficiently widespread amongst market participants, it may push back the time at which Transpower has to incur those future costs, resulting in broader market benefits.

In contrast, the AoB charge would *not* provide load customers with efficient incentives to curtail demand because, as we saw in the previous section, the four key conditions for an efficient price signal do not apply to interconnection assets. The price signals provided under the AoB charge would be difficult to estimate, would not reflect the ‘gap’ between nodal prices and LRMC⁴⁴ and customers may be unable or disinclined to respond to them in any event. The potential consequence would be inefficient consumption decisions.

4.1.3 Effects on investment

We agree with the basic principle espoused in the Issues Paper that more efficient grid usage can be expected to result in more efficient investment. However, it is unlikely that the price signal provided by the AoB charge would promote dynamic efficiency in this manner. This is because the shadow price is likely to produce *inefficient* consumption decisions from load, which would give rise to the very outcomes that the Issues Paper is seeking to avoid. Specifically:

- load customers may *not* curtail their demand when it is efficient to do so and the Commission may find itself approving a new grid investment that appears to be efficient, given current and forecast demand; when
- this may be overlooking the fact that the underlying peak demand growth that is driving the investment may itself be inefficient, i.e., it could be reduced by replacing the implicit shadow price with a more efficient price signal.

The same inefficient price signals might also cause load customers themselves to make inefficient investment decisions. For example, they may over- or under-invest in distributed generation or other forms of demand response, in response to shadow price signals that may be inefficient, that have been misunderstood, or have been ignored because of the potential responses of other customers. Finally, the charge would have no effect on where load customers choose to locate.⁴⁵

Because the AoB charge would not lead to more efficient usage by load, it would not lead to more efficient investment.

⁴⁴ Although, as we explained in section 2.2.1, the RCPD charge may not reflect LRMC either.

⁴⁵ The locational investment decisions of load customers are unlikely to be affected in any meaningful way by differences in transmission charges in the overwhelming majority of cases. Residential consumers do not decide where to live based on relative transmission charges and major industrial loads like aluminium smelters and pulp and paper mills can be expected to locate where they have access to key inputs such as deep water ports and forestry resources.



4.2 Effects on decisions by generators

One of the key differences between the existing TPM and the approach proposed in the Issues Paper is the greater number of charges that will be levied upon generators. Currently, all generators pay connection charges and South Island generators pay HVDC charges. Under the proposal, generators would continue to pay connection charges, but *all* generators would be eligible to pay AoB charges – and possibly LRMC charges, if such a price was introduced.

The Issues Paper states that requiring generators to pay AoB charges would provide them with more appropriate incentives when making investment decisions. The theory is that generators would factor the implicit shadow prices into their investment choices when, under the status quo, transmission costs would be ignored (with the exception of connection and HVDC charges). In this section, we consider the impact of AoB charges on generator's decisions, and nodal prices.

4.2.1 Potential effects of an efficient price signal

Levying an additional fixed charge on generators would increase the average expected wholesale electricity price required to make new generation investments commercially viable.⁴⁶ This may serve to delay the point at which new generation plant comes online – or change the 'build order' which would, in turn, result in higher future wholesale prices than would otherwise have been the case. Of course, this would not be problematic if those decisions were being made in response to an efficient, cost-reflective price signal of long-run transmission costs.

Levying additional transmission charges on generators would increase their costs and result in higher wholesale prices.

Specifically, a generation 'build order' in which the plants take into account an accurate estimate of the forward-looking costs of transmission could be more efficient from a 'whole of system' perspective than a schedule in which generators had not had to account for those costs (because they do not have to pay for them).⁴⁷ By way of simple example, imagine that two prospective generation projects – Plant A and Plant B – are identical in every respect except for their location:

- if generators do not have to pay interconnection costs, Plant A costs \$90 to build (using round numbers) and Plant B costs \$100 – which means that Plant A is built first, since it is cheaper (and otherwise identical); but
- if Plant A would impose an additional \$30 in long-run transmission costs, and Plant B only \$10, and those generators had to pay those costs, then Plant B would be built first, since has the lower *total* cost, i.e., \$110 vs. \$120.

⁴⁶ Specifically, it would increase a new generator's 'break-even' points, i.e., it would render a generator that was only marginally profitable under the existing TPM, unprofitable. Wholesale electricity prices would therefore have to increase to cover existing generators' higher costs. This is consistent with what one would expect to observe in any competitive market when input prices increase, i.e., those higher costs are passed-through to some degree.

⁴⁷ Although recall that, for the reasons set out above, transmission costs would probably have no bearing on these decisions, most of the time.



In these circumstances, application of a cost-reflective transmission charge would lead to higher wholesale prices to cover the additional costs that generators would face. However, the idea is that the increase in wholesale prices would be *more than offset* by the transmission cost savings that arise from the superior locational investment decisions, resulting in a lower total cost of delivered energy, e.g., the ‘total cost’ of Plant B is less than the total cost of Plant A.

This is the fundamental premise of one of the chief sources of benefits in the OGW CBA, which we discuss briefly in section 7. Namely, sending an ‘efficient price signal’ to generators, can change the order and timing of generation build decisions, giving rise to an overall total cost saving.⁴⁸ Moreover, once those new plants have been built, it is assumed they would have no incentive to change their bidding behaviour, since the charge would be fixed.⁴⁹

In our opinion, this theory is robust. However, the analysis in the Issues Paper and the OGW CBA hinges upon one critical assumption – that the AoB charge would be sending an *efficient* price signal to generators. As we have already seen, it would not. It follows that levying AoB charges on generators could have significant adverse effect on their investment decisions, giving rise to *higher* delivered energy prices for consumers. We elaborate below.

4.2.2 Potential effects of an inefficient price signal

Assuming that a new generator could predict accurately the AoB charges that it would pay (which it most likely could not), the methodology would signal to it that its impact on the long-run cost of transmission would be correlated perfectly with the private benefits it would derive from that investment. As we have already touched upon, this does not reflect the way in which new generators may affect Transpower’s long-run costs. By way of simple illustration:

- the long-run impact on Transpower’s future investment costs of connecting a 100MW peaking plant that runs for 10 hours a year might often be much the same as the impact of a 100MW CCGT unit that will run 8000 hours a year; yet
- the private benefits that those two plants might derive from a future investment might be very different, i.e., despite their equivalent impact upon the long-run cost of transmission, their respective ‘shadow prices’ might vary greatly.

Two further aspects of the proposed methodology risk exacerbating these inefficiencies. First, the Issues Paper states that customers that enter an ‘area of benefit’ after an investment has been made would be assigned a share of the costs of those sunk assets. The paper does not explain how those costs would be assigned. It

Levying AoB charges on generators would not provide them with efficient price signals.

⁴⁸ This is calculated by OGW to be \$103m but, for the reasons we set out subsequently, this estimate is not robust.

⁴⁹ This would avoid the undesirable distortions to wholesale markets potentially associated with peak and volumetric charges, which we described at length in our report in response to the previous Options Paper. See: Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015, §3.6.



states simply that any new entrant would need to be treated on the same basis as an identical, existing business and that the charges for that new customer:⁵⁰

'...must be based on a proxy for, but not dependent on, the physical capacity after the participant becomes a designated transmission customer ... It might, for example, be related to the customer's total cost of operation at the site serviced by the customer's connection.'

Assigning a share of the sunk costs of existing assets to *load* customers may have relatively benign consequences for dynamic efficiency since, as we stated earlier, transmission charges would almost never affect their locational decisions (although the same cannot necessarily be said of the residual charge⁵¹). However, the same cannot necessarily be said for generators, where the proposal *could* have any undue influence on entry decisions.

The inefficient shadow price signal could distort generator's investment decisions.

Depending upon *how* AoB charges are assigned to new customer, it might affect the size and/or nature of the plant that is installed, e.g., a generator might decide to install a smaller plant to avoid paying a higher AoB charge. It may also cause new entrant generators to build in sub-optimal locations. This is a further manifestation of the basic problem described above; namely:

- a new entrant might be deemed to derive significantly greater private benefits from the interconnection assets located in 'location A' than 'location B', which would incentivise it to locate in the former, all other things being equal; but
- the impact the generator has on Transpower's future investment costs may be the same in both locations, or it may even be preferable for it to build in location B – which might not be signalled, for the reasons already discussed.

A second potential distortion is created by the differential treatment of interconnection investments that already exist. The Issues Paper proposes to apply the AoB charge to certain 'post-2004' interconnection (and HVDC) assets (those \$50m and above), but not to older assets. The overall effect of this pre/post-2004 distinction is to improve the economics of generation investments undertaken in areas supplied predominantly by assets built before 2004.⁵²

The distinction between pre- and post-2004 would create an additional distortion.

There can be no dynamic efficiency benefits gained from signalling to generators that it is cheaper for them to locate in areas where assets are 'older'. Regardless of whether assets are old or new, their costs are sunk. This distinction can therefore only give rise to dynamic inefficiency. More generally, we not aware of any

⁵⁰ Issues Paper, §7.221 - 7.223.

⁵¹ As we explain in more detail in section 6.1, the proposal to reset periodically the way in which load customers are allocated residual costs may give rise to distortions.

⁵² One specific manifestation of this relatively arbitrary cut-off would be that South Island generators would continue to pay for a significant portion of the cost of the existing HVDC assets – around 45 per cent, based on the preliminary modelling in the Issues Paper.



international transmission pricing arrangements that involve the reallocation of past sunk costs.⁵³

This conclusion is also consistent with the proposal in the Issues Paper to limit the application of the residual charge to load on account of the potential distortions that might arise if it was applied to generators as well. The paper observes that:⁵⁴

'The Authority is of the view that generation is more likely than load to alter its behaviour if the residual charge were applied to both. Thus applying the residual charge to generation is likely to result in more costly distortions to generator investment and operating decision.'

For all of these reasons, in our view, applying the shadow price signal provided to generators via the AoB charge would be likely to have an adverse effect on their investment decisions that would compromise dynamic efficiency. These inefficiencies would result in higher wholesale energy prices and, in turn, more expensive retail prices for end customers.⁵⁵

4.3 Effects on the grid investment process

The Issues Paper again raises the possibility that charging the beneficiaries of investments might cause parties to engage more constructively in the investment approval process, giving rise to more efficient outcomes. We have explained in earlier reports why we disagree with this view. In short, the theory does not represent the practical context in which such investment processes take place.

In our opinion, introducing an AoB charge could would not have a beneficial effect on the new investment approval process – it would have a negative impact. First, no material has been provided to suggest that the Commission's input methodology (IM) has led to inefficient investment outcomes or would do so in the future without an AoB charge.⁵⁶

⁵³ To our knowledge, none of the international examples cited in the Issues Paper encompass such a practice. One can debate at length the merits of these arrangements,⁵³ but the essential point is that these are all examples of different ways to decide/fund *new* transmission investments. We also noted in our first report that the US Court of Appeal has also cautioned against the practice of reallocating sunk costs - see: *Illinois Commerce Commission v FERC*, 576 F.3d 470, 476, pp.2-3 and described in: Green *et al*, *Transmission Pricing Methodology – Economic Critique*, February 2013, §2.4.

⁵⁴ Issues Paper, §7.198.

⁵⁵ Note that the analysis in the OGW CBA does not obviate this conclusion. As we explain in more detail in section 7, the analysis – including the modelling of generation investment – does not reflect accurately the AoB charge methodology, the underlying economics of the power system or the manner in which generators' new entry decisions are made. In our opinion, no weight can therefore be placed on the \$103m in benefits that are said to arise from superior generation investment decisions.

⁵⁶ We note that the EA provided an analysis of the costs and benefits of several recent transmission investments in Table 3 of its Problem Definition Paper that implied that some of those investments were not efficient. However, in our opinion, that analysis was not robust, because they did not account for reliability benefits that do not have an immediate and ongoing market impact. Those estimates are consequently irrelevant, since the greatest benefits of reliability investments tend not to arise during "business as usual" but, rather, when things go wrong. For example, the chief benefit of Orion's investments in earthquake proofing did not materialise until disaster struck. The



Second, even if there *was* a problem arising from asymmetric information (i.e., parties not engaging or participating in an unconstructive manner), the proposed options would be unlikely to address it. Under any conceivable variant of the TPM, there are likely to be submissions from parties that support an investment and from those that oppose it – regardless of whether it is ‘good’ or ‘bad’.⁵⁷ This is because parties will not be motivated by what is best for the market.

Rather, profit-driven enterprises will, quite understandably, want the outcome that delivers the most benefits *to them*. Even if an investment would be likely to maximise overall market benefits, there will inevitably be ‘winners’ and ‘losers’. This will naturally effect what parties have to say to the Commission about any particular investment proposal:

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

The proposal would lead to more unhelpful opposition to all investments.

The Commission will always have to weigh up a number of conflicting submissions – none of which will be motivated by maximising the net market benefit – and exercise its judgement. It will therefore invariably be its role to ‘discover’ the efficient transmission investment outcome. The TPM cannot short-circuit that process, and there is consequently no reason to think that the proposed reforms to the TPM will have any material bearing on the Commission’s separate process.

Third, to the extent the proposal has any effect on the investment approval process, it could well be negative. In particular, it is conceivable that there could be more unconstructive opposition to ‘good’ investments, which may actually make it harder for both Transpower and the Commission to do their jobs. When deciding whether to support any investment, a party will consider whether it might benefit more from something else, such as:

- a smaller investment that entailed lower costs; and/or
- an investment that took place at a later date when demand is higher, i.e., when it might be paying for a ‘lower share’ of the AoB charge.

Issues Paper also states that Carter Holt Harvey has said that some past investments ‘should not have been made or should have been deferred’. However, this statement, which appeared in Carter Holt Harvey’s submission on the previous TPM Options Paper is based on an unsubstantiated contention that those investments were based on ‘overestimates of regional demand growth’ (See: Carter Holt Harvey, *Transmission pricing methodology review: TPM options*, 11 August 2015, p.2.). This does not amount to evidence of inefficient investment.

⁵⁷ See: Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014, §3.1; and Green *et al*, *Economic Review of TPM Options Working Paper*, A Report for Transpower, August 2015, §2.3.



The potential beneficiaries of a ‘good’ investment may consequently oppose it, simply because they would benefit more from another option that offers fewer overall market benefits. The fact that the AoB would seek to ‘lock-in’ beneficiaries once and for all once an investment has been made may also give rise to further unconstructive opposition, because:

- parties may recognise that their actual benefits differ from their anticipated benefits, in which case they may end up paying for assets from which they do not benefit;⁵⁸ and
- these possibilities may make them more likely to agitate against investments from which they may benefit, simply because they fear the possibility of being subsequently burdened with a disproportionate share of the costs.

Parties would also be expected to focus unduly on the subjective assumptions that underpinned their own estimated private benefits.

Finally, as we explain in more detail in section 5.2, because the AoB charge would require Transpower to estimate the benefits that parties are expected to derive from investments over its entire life (e.g., 40 to 50 years) it is inevitable that parties would focus on the assumptions underpinning their respective benefit calculations. Because many of these would be intrinsically subjective and impossible to ‘lock in’, this would be a recipe for ongoing controversy and productive inefficiency.

In our opinion, the introduction of an AoB charge would therefore not necessarily provide more useful information for the Commission, overall. Instead, it might serve simply to create more *unconstructive* opposition to all investments – including those that would maximise net market benefits. It would also cause undue focus on subjective modelling assumptions that have disadvantaged particular customers. This would not aid the discovery of efficient investments – it would hinder it.

4.4 Summary

The Issues Paper assumes that the AoB charge would provide customers with an efficient forward-looking price signal. As we explained in section 3, it would not. The benefits that are forecast to flow from introducing such a price signal would therefore not eventuate, in practice. Instead, the price signal might cause load and generation to make *inefficient* consumption and investment decisions, and hinder the new investment process, as Table 4.1 summarises.

⁵⁸ The EA highlighted this risk in its first Issues Paper in 2012. See: Electricity Authority, *Transmission Pricing Methodology – issues and proposal, Consultation Paper*, 10 October 2012, paragraph 6.5.5.



Table 4.1: Potential inefficiencies arising from the shadow price signal

	Load	Generation
Operation	<p>Because the four key conditions described above do not hold, the AoB charge would not enable Transpower to send efficient signals to customers to curtail demand when constraints start to re-emerge in the future.⁵⁹</p> <p>This could result in Transpower having to invest to alleviate constraints sooner than it would otherwise have needed to if an explicit price signal had been sent to customers via the TPM.</p>	<p>Levying AoB charges on generators would increase the costs of operating plant and, in turn their 'break-even' points. This would result in higher wholesale market prices to cover those higher costs.</p> <p>It is unlikely that those higher wholesale costs would be off-set by long-term transmission cost savings because, as we note below, the AoB charge would be unlikely to incentivise efficient new investment decisions.</p>
Investment	<p>Levying AoB charges on load customers is unlikely to affect their locational decisions since, in the vast majority of circumstances, other factors would have a far greater bearing. For example, residential customers do not decide where to live based on transmission charges, and the locational decisions of large industrial customers will generally be swayed by practical factors such as the location of forests, ports, etc.</p>	<p>Because the four key conditions described above do not hold, the AoB charges would not provide generators with an efficient price signal – especially because expected private benefits are not synonymous with forward-looking transmission costs.</p> <p>The proposal would also send the counterintuitive signal that it is cheaper for generators to locate where assets were built before 2004. This would be likely to compromise dynamic efficiency.</p>
Engagement in grid investment processes	<p>If the AoB charge is introduced, both load and generation customers would have stronger incentives to oppose <i>all</i> investments – including those that maximise net market benefits – and advocate for alternatives that may be less efficient, but would maximise their own private benefits. The requirement to recover the costs of an investment based on estimated private benefits over the life of an investment would serve to exacerbate the scope for disputes. Customers would naturally focus on modelling assumptions that have affected them adversely. This additional unconstructive opposition could compromise dynamic efficiency if it results in 'good' investments being blocked.</p>	

The AoB charge therefore does not meet the *first* objective of efficient transmission pricing described in section 2. Namely, it would not provide an efficient signal to customers of future costs before investments are made to elicit desirable changes in behaviour. Any benefits from the AoB charge would consequently need to reside in its ability to meet the *second* objective of efficient transmission pricing, i.e., minimising distortions to demand *after* investments have been made. This issue is considered in the following section.

⁵⁹ Note that, although inefficient load-shedding would cease in the near-term if the proposal is implemented, this would be on account of the removal of the RCPD charge, not the introduction of the AoB charge – and there are many other ways to achieve that same outcome, e.g., by measuring contributions to RCPD over more periods.



5. Would the AoB charge result in a more efficient allocation of sunk costs?

The previous section explained why the proposed AoB charge would not provide efficient incentives for customers to *change* their behaviour in desirable ways *before* investments are made. This section therefore focuses on whether the charge might *discourage* customers from changing their behaviour in *undesirable* ways *after* investments have been made. The key question is whether it would give rise to a more efficient allocation of sunk costs, promoting productive and allocative efficiency. We explore this issue in the following section.

5.1 Are significant static efficiency gains achievable?

The extent to which changing the way in which the sunk costs of the existing grid are recovered from customers can give rise to allocative efficiency benefits depends first and foremost upon the degree to which the current TPM is giving rise to unwelcome distortions. As we have explained in earlier reports,⁶⁰ this depends upon the current level of inefficiently unserved demand, i.e., whether the current interconnection and HVDC charges result in:

- some parties not consuming as much of those transmission services as they would have at a price that reflected their private benefit; or
- some parties not consuming the services at all, i.e., refraining from consuming altogether because they are not willing to pay those charges.

In these circumstances, demand that could have been served at prices that generate positive economic profits goes unmet, producing a deadweight loss. Any reduction in that 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 proposal. Put another way, the only way in which reallocating sunk costs can deliver an allocative efficiency improvement is if:

- some customers face *lower* prices than under the current TPM and consequently *increase* their consumption of transmission services; and
- those customers that face *higher* prices do not inefficiently *reduce* their demand, which would serve to undo the efficiency gains arising from the former.

This consequently begs the question: to what extent is there likely to be material unserved demand associated with the current TPM? In our opinion, there are two key sources of potential allocative inefficiency arising from the way in which the sunk costs of existing investments are recovered under the status quo – both of which are identified in the Issues Paper and the OGW CBA (although the OGW CBA only considers the first of these two effects). These are:

There are two key sources of allocative inefficiency under the current TPM.

⁶⁰ See for example: Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper*, A Report for Transpower, March 2014, §2.2.



- the incentive created by the RCPD charge to shed load to avoid interconnection charges, even though there is significant spare capacity throughout much of the grid, i.e., total peak demand is generally well below available capacity; and
- the potential inefficiencies arising from the Historical Anytime Maximum Injection (HAMI) charge applied to HVDC assets, i.e., the incentives created for South Island generators to strategically withhold supply.

It is not necessary to introduce an AoB charge to achieve these allocative efficiency gains.

In terms of the first, we agree with the observation in the Issues Paper that load customers may currently have undue incentives to reduce their use of sunk interconnection assets so as to avoid RCPD charges through, say, the use of locally-based distributed generation. This is a potentially significant source of static inefficiency, since there is currently spare capacity throughout much of the grid, and much of the demand that is currently being curtailed might be served more efficiently by using the existing transmission grid assets.

However, as we have already seen, the achievement of those allocative efficiency gains does not hinge on the introduction of an AoB charge. In order to eliminate the existing inefficient level of unserved demand, all that needs to happen is to remove – or reduce the strength of – the existing RCPD charge. As we explain in more detail subsequently, there are likely to be simpler, more effective ways of achieving this objective than introducing an AoB charge.

In terms of the inefficiencies arising from the current HAMI-based parameter, these were recognised by both Transpower and the EA during the recent operational review.⁶¹ However, as we explained above, the inefficiencies associated with this charging parameter have been reduced substantially by the pending transition to a ‘South Island mean injection’ (SIMI) charge. Although the SIMI charge will not officially be in place until next year, we understand that customers are already changing their behaviour in response to it, i.e., by offering more capacity.

There is clear potential for the large wealth transfers to give rise to allocative efficiency losses.

For those reasons, there appears to relatively ‘little work’ for an AoB charge to do in terms of *improving* the efficiency with which the existing sunk assets are utilised. However, it is conceivable that the introduction of the charge would give rise to a material *reduction* in static efficiency. This could stem from the very large shifts in the allocation of sunk costs onto load customers. The most striking example is the reallocation of existing HVDC costs.

Under the indicative modelling in the Issues Paper, South Island generators would continue to pay around half the HVDC costs – but the other half would switch to load; primarily to customers located in the North Island. The net present value (NPV) of that transfer would be around \$750m over the 20-year assessment period

⁶¹ Electricity Authority, *HVDC component of Transpower’s proposed variation to the Transmission Pricing Methodology, Decisions and reasons*, 14 August 2015.



in the CBA (around \$65m per annum). The efficiency benefit that is said to arise from this reallocation is \$13m,⁶² i.e., less than 2 per cent of the wealth transfer.

It would require only a small demand response on the part of those load customers to offset the \$13m estimate. For example, if those additional transmission charges were passed-through even only *partly* as volumetric charges to end customers (i.e., if distribution businesses moved to more efficient pricing methodologies), and this caused even a small reduction in the use of those existing assets by those load customers, then the resulting allocative efficiency loss would, in all likelihood, be much larger than \$13m over a 20-year period.

At the very least, it is not reasonable to assume that such large wealth transfers (around an additional \$850m on load customers in total) would have *no* impact on allocative efficiency – which is the position adopted in both the Issues Paper and the CBA. It is not obvious therefore that there are material allocative efficiency gains that could be delivered via an AoB charge, but there does appear to be significant potential for allocative efficiency losses.

In terms of productive efficiency, it is worth noting that the TPM is now familiar to most – if not all – industry participants, and so the ongoing costs of administering it are relatively modest. However, the Issues Paper questions its durability, noting that issues such as HVDC pricing have been extremely controversial and that the current methodology has been under review in one way or another since it was implemented on 1 April 2008, giving rise to ongoing costs. That is undoubtedly true.

However, transmission pricing was a source of controversy well before the current TPM was put in place.⁶³ This is an unremarkable consequence of the economics of transmission. Changes in the TPM that have only modest efficiency implications can still give rise to large transfers of wealth between industry participants – as the above example serves to highlight. It is therefore only natural that profit maximising firms have lobbied continuously to have the methodology changed in their favour.

In other words, although there has undoubtedly been a significant sum spent on lobbying under the current TPM, another methodology may have been equally controversial – perhaps even more so. In our opinion, it is consequently unclear whether there is significant scope to reduce ongoing administrative costs and improve productive efficiency through reforming the TPM.

In fact, as we explain in more detail below, it is quite possible that the proposed design of the AoB charge would *increase* ongoing costs unless it is modified. First

The proposed design of the AoB charge could give rise to higher costs, i.e., to productive inefficiency.

⁶² As we explain in section 7, the \$13m estimate is unreliable, because the methodology by which it has been derived is flawed. But even if one was to assume for the sake of argument that it was robust, \$13m is very small number, compared with the size of the wealth transfer.

⁶³ For example, Contact and Meridian launched a successful judicial review of the process the EA's predecessor undertook to arrive at its 2005 pricing guideline, see: *Contact Energy Limited and Meridian Energy Limited v Electricity Commission* (CIV 2005 485-624, 29 August 2005, McKenzie J). For an overview of the process by which the current TPM was determined – including the various controversies, see: Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009, p.17.



and foremost, estimating the private benefits that would arise over the entire lifespan of an interconnection investment would be very challenging, in practice. The potential for ongoing controversy is clear – particularly (and perhaps somewhat ironically) if more complex methodologies are employed.

5.2 Estimating private benefits: the complexities and costs

It would not be possible for Transpower to forecast with any meaningful precision the temporal dynamics of private benefits over the 30- to 50-year (or thereabouts) life of an interconnection asset when deriving AoB charges. There are numerous practical factors that would serve to complicate any such exercise. These complications include (but are not limited to) the following:

- if an investment is being sized so as to cater for potential future entrants, (e.g., if significant demand growth is forecast, or more generators are expected to connect at some point), it would be very difficult to factor those developments into the allocation of charges in any robust way;
- any private benefit analysis that was dependent upon future nodal prices would require assumptions to be made about how generators may bid into the market in the future – in our opinion, there is likely to be simply no robust way to mimic this type of market process through modelling;
- the extent to which a party benefits from an asset at any particular time may depend upon exogenous factors, such as whether it is a ‘dry-year’, and so any analysis of benefits would need to take into account factors such as forecast hydrological conditions – an exercise fraught with potential for error; and
- in the case of *existing* assets (remembering that the Issues Paper proposes to apply the AoB methodology to some large investments made post-2004) there is the further substantial additional complexity of hypothesising what would have happened in the *absence* of the investments in question.

Accurately estimating private benefits over the entire life of an interconnection investment would be impossible.

The indicative modelling in the Issues Paper does not attempt to address these temporal complexities, since it only models charges for a single year – 2019. Moreover, to even come up with that single year of indicative prices, many subjective assumptions have been made about forecast nodal prices throughout the country, the value of lost load and which generators are going to be in the market at that future date – all of which could be challenged.⁶⁴

More complex approaches would not necessarily yield more accurate estimates, but they would give rise to many more costs.

In our opinion, these challenges cannot be overcome through the use of more sophisticated approaches to estimating private benefits – such as the vSPD method used in the Issues Paper. Rather, more complex approaches may be no better at predicting the pattern of private benefits over 30-50 year periods than simpler approaches. While these approaches might seem more precise, in our view, that is largely false precision. More complexity does not necessarily mean greater accuracy.

⁶⁴ Similarly, the OGW CBA, which is undertaken over a 20-year assessment period, does not even attempt to estimate the AoB charges that parties would actually pay in each of those years. Instead, it incorrectly assumes that each customer would pay a charge equal to the regional LRMC of transmission. In other words, the OGW CBA has not actually modelled an AoB charge.



We note, for example, that the Midcontinent Independent System Operator (MISO)⁶⁵ acknowledges these practical limitations in its particular variant of an AoB charge methodology. Namely, only 80 per cent of the costs of qualifying new investments are allocated to the perceived beneficiaries (in ‘Local Resource Zones’) – with the remaining 20 per cent recouped via a system-wide postage stamp. This recognises the considerable margin for error that exists in estimating benefits, i.e., there is a ‘downward adjustment’ to cater for that uncertainty.

However, whilst greater complexity does not mean greater precision – it *does* mean greater administrative cost and, in all likelihood, more scope for disputes. For example, to apply the vSPD approach, Transpower would need to design and undertake a series of ‘modelling runs’ every time it built an asset valued \$5m or more. In order to do so, it would need to come to a view on the various parameters set out above, including the value of lost load, forecast nodal prices, expected future demand growth and so on.

Arriving at estimates of parameters would require subjective judgement, which could affect significantly the charges that different customers were assigned. Parties would therefore be expected to continually agitate for these assumptions to be changed, because they know that even a small revision in their favour may significantly reduce their charges. This would lead to additional costs and, in turn, productive inefficiency.

It might be possible for Transpower to ‘fix’ *some* of the key modelling parameter values in advance for a period, e.g., five (perhaps even ten) years. However, that would neither improve the accuracy of the resulting benefit estimates, eliminate the potential for significant ongoing disputes, nor reduce the level of controversy and cost relative to the existing TPM, because:

- there would inevitably be substantial dispute over any initial values assigned to these modelling parameters, and the values assigned at each subsequent review – given the potential value at stake, those disputes could conceivably culminate in costly litigation (such as judicial reviews); and
- because any model would be likely to have significantly more constituent parts than the existing TPM (an inevitable consequence of using a complex quantitative model), there would be a wider ‘potential set’ of parameters over which there would be controversy when the TPM was set/revisited.

In any event, even if fixing modelling inputs in advance was an effective solution (which it is not), it would not be possible to lock-in every value. Taking the vSPD approach as an example, occasions would arise when the model could not be ‘solved’ with those pre-determined parameter values. Transpower would therefore need to have the flexibility to exercise its judgement when defining counterfactuals in order to produce a vector of prices. It could never become a simple ‘crank the handle’ exercise.

Complex approaches would give rise to more disputes than more pragmatic allocation methodologies.

⁶⁵ MISO provides open-access transmission service throughout the Midwest and Southern United States and in and in Manitoba, Canada.



The nature and effect of the judgements that Transpower would need to make may vary based on many factors, including the level of demand and other grid constraints. If Transpower must make a 'judgement call' in order to 'solve' the model, there is a good chance that there will be 'winners and losers' – and the losers can be expected to challenge that decision if the sums in question are significant. This would be a recipe for ongoing controversy, cost and productive inefficiency.

It follows that, if an AoB charge was to be implemented, it would be important for the cost allocation methodology to be undertaken at a more 'aggregated' level. In particular, areas of benefit would need to encompass more than just individual nodes and costs/benefits should be identified for customer 'groups' (i.e., all load and all generation in an area of benefit) rather than for individual customers.

5.3 Other avenues for ongoing costs and distortions

The potential for inefficient distortions and productive inefficiency from additional administrative costs extends beyond the basic design of the AoB charge, i.e., how areas of benefit are identified, and costs are allocated to perceived beneficiaries. There are also a number of further more specific avenues through which the proposed methodology could give rise to additional costs and disruptions. We identify these in the following sections.

5.3.1 Greater scope for continual disruptions and disputes

There are several more specific aspects of the proposed AoB methodology beyond the initial estimation of private benefits that may serve to exacerbate the level of ongoing administrative costs. This could result in further increases in administrative costs across the sector – and for Transpower in particular.

The proposed \$5m threshold for the application of the standard methodology would encompass a large number of investments.

First, the methodology would apply to *all* new HVDC and interconnection investments, i.e.:

- the threshold for the application of the 'standard' methodology is proposed to be \$5m – which is not particularly high, and would therefore encompass a large number of investments; and
- although investments below \$5m would only require the application of a 'simplified' methodology, no real guidance is provided as to what that would entail – which, in itself, would generate controversy.

Second, there would be a broad array of circumstances in which Transpower's planning processes could be interrupted under the proposed methodology, or its cost allocations reset, including:

Many things could disrupt Transpower's planning processes, or cause charges to be revisited.

- the marginal benefit adjustment mechanism could result in Transpower's investment planning and processes being regularly interrupted, and it would require it to estimate prospective AoB charges for the beneficiaries of each investment (and potentially do the same for alternative investment options);
- as we explain in more detail subsequently, the proposed broadening of the prudent discount policy could require Transpower to devote resources to



assessing more discount applications, and to examine business cases from industries in which it has no expertise;

- there would also be 'trigger' mechanisms for asset values to be optimised and for prices to be revisited following 'material changes in circumstances' – to be sure, these tools may have benefits, but they would also give rise to additional administrative costs; and
- Transpower would also have to produce a methodology to apply the AoB charge to customers that 'enter' an area of benefit after an investment has been made – as we explained earlier, no guidance has been provided as to how to do so, without risking distortions.

Some of the proposed mechanisms – such as the 'optimisation' and 'material change of circumstances' triggers may be quite useful, in that they might make the methodology more adaptable, over time. However, on the whole, it is likely that the proposal would be more contentious than the status quo – especially if a complex modelling approach such as the vSPD approach is employed.

5.3.2 Time profile of AoB charges

In our report in response to the previous Options Paper we explained why applying a depreciated historical cost (DHC) approach to set prices for bespoke investments will yield an inefficient time-profile of charges. Specifically, it results in prices that are highest immediately after a new asset had been built (i.e., when no straight-line depreciation has been applied) and lowest right at the end of its estimated life when the asset was nearly fully depreciated. This is the opposite of what efficient transmission pricing requires.

For the most part, the proposal in the Issues Paper addresses this problem by recommending that all *new* investments subjected to the AoB methodology in the future to be priced based on a replacement cost methodology. The intention in these instances is to employ a methodology that will produce smooth prices throughout the life of the assets, i.e., consistent with more 'serviced-based' pricing. However, there is one notable exception.

The Issues Paper proposes to use a DHC approach when applying the AoB methodology to the *existing* interconnection and HVDC assets that have been earmarked for the charge. The reasoning underpinning this distinction is that switching from a DHC approach to a replacement cost approach part-way through those assets' lives would supposedly risk customers paying more than the total costs of those investments.

Insofar as the HVDC assets are concerned, that is incorrect. Transpower's IPP contains a specific HVDC revenue allowance, which limits the amount that it is permitted to recover for those assets under the TPM. So even though AoB charges would be applied to both Poles 2 and 3 from 2019, Transpower would *not* be able to set charges that resulted in it 'over-recovering' the costs of those investments. That would not be possible, since its IPP would prevent it.

There is no reason to think that applying a replacement cost approach to existing assets would result in 'over-recovery'.



A replacement cost approach should be used for all assets subjected to the AoB charge – including existing assets.

There is also no basis to think that customers might end up ‘over-paying’ for the interconnection assets that comprise the remaining investments. The most important thing to realise is that Transpower has *not* applied bespoke interconnection charges for particular assets – including those that have been earmarked for AoB charges. Instead, it has:

- calculated the annual revenue that it must recover through the TPM – the majority of which comprises a return on and of the depreciated value of its regulatory asset base, which comprises *all* of its assets, old and new; and
- set RCPD-based charges for *all* of its interconnection assets, i.e., there is a single bucket called ‘interconnection revenue’ – there are not ‘multiple buckets’ that allocate the costs associated with particular assets to particular customers.

It is therefore not valid to ask whether applying a replacement-cost valuation approach to certain assets would result in some customers ‘overpaying’ for those investments. There is no answer to this question, because there has been *no price* for those specific assets under the TPM – it is not a relevant ‘thought experiment’. There have instead been prices that reflect the value of *all* interconnection assets, which have been paid by *all* customers.

Furthermore, even if there was some basis to think that customers might ‘over-pay’ for those particular interconnection assets, in our view, that would still not necessarily be a sufficient reason to employ a DHC methodology. The total amount of revenue that Transpower would recover would not change, because that is determined by the Commission’s IMs. All that would happen is that more of that revenue would be recovered via the AoB charge, and less through the residual.

The potential efficiency consequences of that redistribution might be relatively benign – especially compared with the aforementioned disadvantages that would be associated with the inefficient time profile of DHC-based charges. For all of those reasons, we do not consider that it would be necessary or efficient to apply a DHC approach to the existing assets earmarked for AoB charges. If the charge is implemented, a replacement cost approach should be used in *all* instances.

5.3.3 Total investment costs may exceed total private benefits

The interplay between clauses 6 and 9 of the draft Guidelines has the potential to cause further distortions and controversy. Clause 6 states that the AoB charge ‘must recover the full cost of each asset that is included in an eligible investment’.⁶⁶ Separately, the Issues Paper makes it plain that no customer should ever be required to pay an AoB charge that exceeds Transpower’s assessment of their *expected*⁶⁷

⁶⁶ Issues Paper, p.198.

⁶⁷ Note that, for the reasons set out in section 5.2 that a customer may *ultimately* end up paying a charge that exceeds its private benefit, since it would be impossible for Transpower to forecast those benefits with any real precision. However, the key point is that Transpower should not allocate costs in a way in which that is *expected* to occur.



private benefit. For instance, clause 9 of the draft Guideline defines an area of benefit as:⁶⁸

‘...an area in which at least one designated transmission customer is expected to receive a positive net benefit from the eligible investment.’

It is conceivable that the annual costs to be recovered via the AoB charge would exceed the total private benefits.

The potential problem that this creates is that it presupposes that the total cost of an investment will *always exceed* the total private benefits that it generates. That may not always be the case. For example, 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*.

The effect of the proviso is that the cost of a reliability investment might well *exceed* the expected, net private benefits (unlike for an “economic investment”). For these types of investments, recovering 100 per cent of the investment cost from the identified ‘private beneficiaries’ in the manner contemplated by clause 6 of the draft Guidelines, might be seen as being inconsistent with clause 9, which states that no customer should pay more than its estimated private benefit.

Furthermore, the strong economies of scale associated with transmission investments mean the private benefits from an investment may exceed its costs when measured over its *entire life* – but *not in the early years*. It is quite common for large investments to give rise to significant spare capacity in the initial years of their lives, only for that capacity to be steady ‘used up’ as demand – and the quantum of private benefits – grows.

The Guideline should make it clear that AoB charges are capped at customers’ estimated private benefits.

That being the case, it is possible that Transpower might undertake an efficient investment that will maximise net market benefits yet not be able to recover the annual sum that it needs to from identified beneficiaries in the early years without those charges exceeding their private benefits. The more efficient time profile of charges contemplated in the Issues Paper described above would help (at least for new investments) – but it would not necessarily eliminate the problem.⁶⁹

There are at least two solutions to this. The first would be to simply assume that the *unidentified* beneficiaries of reliability investments are, say, all load customers – and to allocate those costs in some manner, e.g., by defining an ‘area of benefit’ that encompassed, say, the whole country. The second approach – which would

⁶⁸ Issues Paper, p.199.

⁶⁹ Specifically, the ‘flat’ depreciation profile that appears to be contemplated in the Issues Paper would avoid the problem those arose with the charges proposed in the previous Options Paper, which were at their highest right after an investment had been made, and gradually declined to zero over the asset’s life. However, even with the initial prices being lower than they would be under a straight-line depreciation approach, the total sum to be recovered may still exceed total private benefits, for the reasons set out above. This could be addressed through a ‘tilted annuity’ approach to depreciation, e.g., where an *increasing* amount of revenue is recovered over time. However, that would introduce additional complications, e.g., deciding upon the ‘size’ of the tilts, and whether different tilts should be applied to different investments.



ultimately amount to the same thing – would be to change the requirement in clause 6 of the draft Guidelines.

Specifically, it could be modified so as to say that the AoB charge must recover either the full cost of each asset that is included in an eligible investment, or the total estimated private benefits – *whichever is lower*. If the total identifiable expected private benefits are lower than the total investment costs (which, for the reasons set out above, is conceivable), that shortfall could then be recovered through the residual charge.

5.4 Is a fairer, more durable allocation achievable?

The analysis set out in the previous sections suggests that it is unlikely that the AoB charge would result in a more efficient allocation of sunk costs. However, it may still produce a more equitable allocation of charges. Indeed, as the Issues Paper observes, and as we noted in our previous report, ‘fairer’ charges have the potential to be less contentious and more durable.

For example, throughout the consultation process hitherto, much has been made of the fact that there are currently customers – often in the South Island – who are paying for investments that are being used to deliver services largely to other customers – often in the North Island. Similarly, South Island generators have long argued that they are not the only parties that benefit from the HVDC link. In both cases the negatively affected parties have claimed that this is not fair, and lobbied for the TPM to be changed.

It is unclear whether the AoB charge would yield a more equitable cost allocation, since ‘fairness’ is subjective.

The trouble, of course, is that unlike efficiency – which is an objective, measurable standard – equity is inherently subjective. What might seem fair to one party might seem unfair to another. It can also be affected by intertemporal considerations. For example, whilst it might seem ‘fair’ for the beneficiaries of new investments to pay for them, it may seem less so if the beneficiaries of past investments have been treated differently – or if there have been other offsetting benefits.

It might also be said to be somewhat ‘unfair’ to change the way in which sunk costs are allocated so soon after a major investment programme. Rightly or wrongly, this might be viewed by some as it ‘shifting the goal posts’ and might even undermine the confidence that some participants have in future investment approval processes – and transmission pricing frameworks. Put simply, ‘equity’ is often in the eye of the beholder – and perspectives can vary considerably.

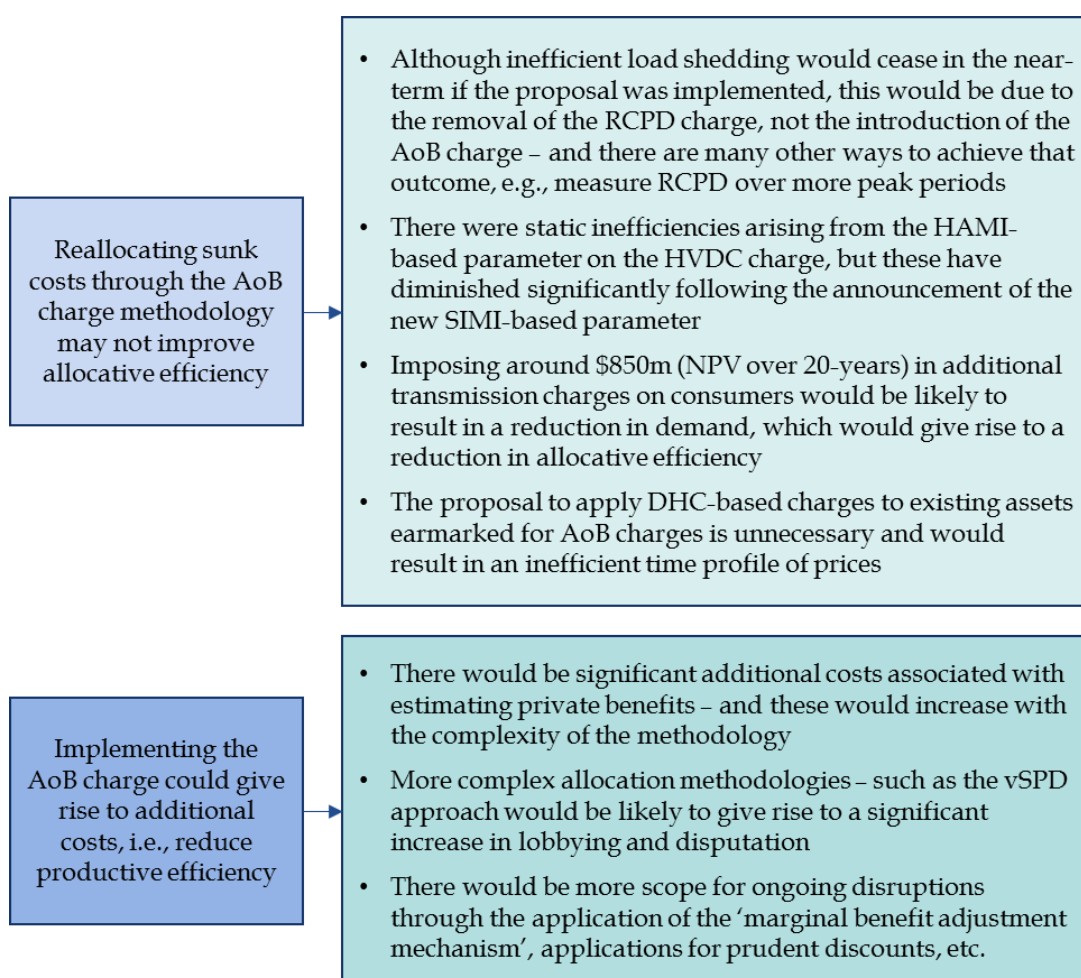
It is for this reason that objective efficiency considerations should, rightly, trump subjective equity considerations in regulatory decision making. In particular, if changing the TPM to address perceived inequities in the allocation of costs would lead to inefficient changes in usage and investment decisions, then those inefficiencies should obviate any reform from occurring. In our opinion, fairness – whilst relevant – should remain a secondary consideration.



5.5 Summary

The Issues Paper suggests that the AoB charge would give rise to a more efficient allocation of sunk costs. In our view, that is unlikely to be the case, since an AoB charge would appear not to address any of the distortions that currently arise under the status quo.⁷⁰ However, the significant reallocation of sunk costs of existing assets to load customers that is contemplated in the Issues Paper could might static efficiency losses. Implementing the methodology could also give rise to additional administrative costs. Figure 5.1 summarises.

Figure 5.1: Potential effects on static efficiency and administrative costs



It is conceivable that the proposed cost allocation methodology might be perceived to be ‘fairer’ than the existing approach and may serve to improve the durability of the arrangements. However, equity is an intrinsically subjective concept. There also seems little doubt that any such benefits would be accompanied by additional costs which would serve to offset those advantages – and, quite possibly, significantly outweigh them.

⁷⁰ At least once the inefficiencies associated with the RCPD charge are addressed which, as Figure 5.1 illustrates, can be achieved through other means.



6. Allocation of the residual charge

In this section we consider the proposed design of the residual charge. We begin by considering whether the charge might give rise to distortions. We then consider whether there might be other options available beyond the three that have been specified in the draft Guidelines. Finally, we consider whether it is necessary or desirable to extend the prudent discount policy in the manner contemplated in the Issues Paper to deal with instances in which the residual charge gives rise to inefficient incentives.

6.1 Potential for distortions

The purpose of the residual charge is to recover the remaining amount of Transpower's annual revenue requirement in the least distortionary way possible, i.e., it is intended to be a 'non-distortionary tax'. The Issues Paper concludes that this can be best achieved through a charge levied on load. We agree. Load customers are the logical candidates for such a charge since, as the Issues Paper highlights their decisions are less sensitive than generators' to transmission charges.

The Issues Paper suggests also that, because the three capacity-based allocators it has proposed (line or transformer capacity and gross anytime maximum demand (AMD)) would be measured over many years, that this would remove any incentives that those customers have to change their behaviour in inefficient ways. For example, it was suggested at the Auckland TPM workshop that the prospect of paying a higher residual charge in, say, 10 years' time would not be a relevant factor in any investment analysis being undertaken today.

Even capacity-based allocations could give rise to unwelcome distortions.

In our opinion, businesses might not necessarily see things in that way all of the time. For example, a business might take the view that it will err on the side of 'building small' every time it invested in lines or transformers, with a view to receiving a significant pay-off several years hence. Moreover, that incentive would grow over time, e.g., as the 'reset' of residual charge approached, there would be more and more incentive for customers to act in potentially inefficient ways so as to reduce their future residual charge allocation.

Indeed, it is worth remembering Transpower's experience with the HVDC charge, where it was thought that calculating HAMI on a 5-year basis would remove the incentives that South Island generators would have to avoid the charge. As we now know, that thinking was misguided and plants inefficiently strategically withheld capacity. In our view, one therefore cannot rule out the possibility that the proposed allocators would result in adverse, unintended reactions from the load customers upon whom the charges are levied.

The proposed approach also raises legitimate questions related to the 'fairness' of the resulting reallocation of sunk costs. As we noted in section 5.4, it might be said to be somewhat 'unfair' to change the way in which sunk costs are allocated through the residual charge, so soon after a major transmission investment



programme. Furthermore, some of the wealth transfers are very significant, and fall disproportionately on load customers.

Electricity Ashburton receives a much larger allocation, by virtue of the fact that it is 'summer peaking' – in large part because of the heavy investment in irrigation that has occurred throughout its network footprint. Customers in that area might justifiably complain that some of that investment may not have proceeded if they had known that their network charges would increase in the future (as we note below, the collapse in world dairy prices has not helped matters).⁷¹ Moreover, it is not obvious why it would be efficient or desirable to charge a customer the same amount for its peak demand if it does not coincide with coincident peak demand throughout the grid.

In a similar vein, major load customers such as, say, Norske Skog, might reasonably say that, had they known that a capacity-based allocator was going to be used to determine their costs, then they would have made quite different investment decisions in the past. More generally, *any* customer that has invested to reduce their use of existing transmission capacity may have cause to feel aggrieved by any switch to a capacity based charge.

Rightly or wrongly, this might be viewed by some as a form of 'hold up', where one party has incurred costs that cannot be recouped, only for another party to subsequently 'change the terms of the deal', as it were. As we explained above – and in more detail in our report in response to the Consultation Paper on pricing principles for distributed generation⁷² – it is possible that this might undermine investors' confidence in the regulatory regime, risking further distortions.

6.2 No need to restrict options

The draft Guidelines would limit Transpower's choice of allocation-factors to three options, i.e., line capacity, transformer capacity and gross AMD. The Issues Paper does not set out the reasons why alternative options for allocating the residual to load have been ruled out. In our opinion, *all* potential allocation methods should be considered – either by the Authority in setting the Guidelines, or tasked to Transpower to review as part of development of the TPM itself. The latter could be achieved by amending the Guidelines so as to either:

- simply require Transpower to select an allocation methodology that would be least likely to give rise to distortions (taking into account the factors above), i.e., to eliminate all references to the three specific methodologies; or

⁷¹ EA Networks might also characterise its higher proposed allocation as 'unfair' on the basis that, if its load was to theoretically 'disappear', most of the existing transmission infrastructure might still be needed to transport electricity north to Christchurch to cater for winter peaks.

⁷² Axiom Economics, *Economic Review of Distributed Generation Pricing Principles Consultation Paper*, A Report for Transpower, July 2016, §5.3.2. See also: Green *et al*, *Alternative Approaches to Light-handed Regulation*, A Report for the Essential Services Commission, 5 March 2004, §4.3.

The design of the residual charge could be seen as unfair, and inconsistent with investors' legitimate expectations.



- leave the existing references to the three options – but amend the Guideline so as to give Transpower the flexibility to implement another approach if it considers it would be superior, i.e., to make the list ‘non-exhaustive’.

There would seem to be no obvious downside to providing Transpower with additional discretion on this point – indeed, the EA would still have to test any proposal against the statutory objective. Moreover, there would be a significant potential upside, since there could well be superior ways to allocate the residual charge than the three approaches set out in the Guideline. Some candidates include:

- an historical average of *median* demand, which would be much harder to change over time, as ‘resets’ approach; and
- a weighted average of historical RCPD (this possibility was raised by Trustpower at the Wellington TPM workshop).

At first blush, these two alternative options would appear to offer some potential advantages. For example:

- it could be more difficult for a customer to reduce its median demand than, say, its transformer capacity – which may go some way to addressing the potential distortions highlighted above; and
- applying a weighted average of historical RCPD would reduce the extent of wealth transfers – and the prospect of ‘hold up’, since parties that have invested to reduce their contribution to RCPD would have those efforts recognised – at least to some degree – in their residual charge allocation.

To be clear, we are not saying that either of these approaches would necessarily be superior to the three methodologies proposed in the Issues Paper – we have certainly not considered them thoroughly. But the key point is that they *might be* – or there might be yet another approach that is more efficient. It follows that *all* potential approaches need to be considered before a final decision is made.

6.3 Prudent discount policy

The Prudent Discount Policy (PDP) is intended to address situations in which the TPM – and the interconnection charge in particular – provides parties with incentives to act in ways that are privately beneficial, but inefficient overall.⁷³ The ‘flat-rate’ nature of the proposed new residual charge means that customers may still occasionally have such incentives if the proposed reforms are implemented. However, the Issues Paper not only recommends retaining the existing arrangements – it proposes to extend them to encompass more scenarios.

The proposal to apply the PDP in situations in which the ‘alternative project’ is investment in generation is sensible. This would appear to address a clear ‘gap’ in the current arrangements that might otherwise lead to inefficient outcomes.

⁷³ For example, it may sometimes be financially advantageous for a customer to bypass the transmission grid in order to avoid interconnection charges – the PDP allows Transpower to grant a discount in such circumstances to avoid needless price increases for other customers.

It is neither necessary nor desirable to limit the allocation approaches available to Transpower.



However, in our opinion, the further proposal to allow Transpower – or even the EA – to extend prudent discounts to businesses that claim that they are at risk of exiting the market unless their input costs fall is likely to be unnecessary and unworkable in practice.

6.3.1 The reform is unnecessary

The proposal to extend the PDP to scenarios in which customers are perceived to be at risk of exiting would require Transpower or the EA to adjudicate on and grant financial relief with a view to ensuring that businesses of importance to ‘New Zealand Incorporated’ remain viable going concerns. Such matters do not obviously fall within their respective remits, and would place Transpower or the EA in potentially very awkward positions.

Transpower or the EA would have an understandable incentive to err on the side of granting discounts – even when they may not be needed.

From a purely practical perspective, neither Transpower nor the EA would want to be seen as the party that was responsible for the departure of a major industrial customer. It is therefore natural to expect that either one of them would be likely to err on the side of granting prudent discounts if given this additional responsibility, since the perceived downside of declining a discount when it is needed may be viewed as worse than the downside of granting a discount that is not really needed.

This incentive problem is exacerbated in this case by the fact that neither Transpower nor the EA is likely to have sufficient expertise to ‘second-guess’ matters such as, say, the Tiwai smelter’s forecast of world aluminium prices – a complication we discuss further in the following section. In other words, there is a clear asymmetry of information which, given the nature of the decisions at issue, would be likely to result in a bias towards the granting of prudent discounts.

This may diminish the incentives that businesses have to find their own ways of improving their efficiency in order to improve profitability – at least until after a discount has been granted. If a business knows that it can apply for a prudent discount, and that the party making that decision will not be well-placed to second-guess the application, or will be eager to avoid being seen as responsible for it exiting, then this may be seen as an easy way to cut costs – even if it is not the optimal approach.

Another important factor that neither the Issues Paper nor the OGW CBA considers in any detail is the nature of the ‘counterfactual’. Both make the assumption that all other customers would be better off if a large customer does not exit, since their transmission charges would be lower than they would otherwise have been. However, the ‘with and without’ test is more complicated than that. For example, customers would *not* be better off if:

- the applicant was gaming the regime and would not have exited;
- another, more efficient operator would have entered and replaced the firm that exited – in that case, granting the prudent discount would result in other customers paying *higher* transmission charges than necessary; and



- electricity spot prices might have decreased significantly if the firm exited, and this reduction in wholesale prices might more than offset any increase in other customers' transmission charges (see more below).

The potential impacts of the departure of a large customer on spot prices are particularly important to consider.⁷⁴ The EA explained at its Wellington workshop that it such effects had not been considered in its analysis – or in the OGW CBA – because they “would be a wealth transfer”. In our opinion, that is not a robust reason to eschew from considering such impacts for two reasons:

- the approach is inconsistent, since a decision to grant or decline a prudent discount would also result primarily in wealth transfers, with sunk costs being redistributed amongst other customers – yet, the OGW CBA determines (wrongly, in our view) that there would still be a \$10m net benefit; and
- significant changes in spot prices *would* have potentially significant impacts upon consumption and investment outcomes and these are likely to be far more significant than any efficiency impacts arising in the transmission market, i.e., the Issues Paper and the OGW CBA should not consider one, but not the other.

Government is in a much better position to make such decisions – and has superior tools at its disposal to grant financial assistance.

In short, the factors that should rightly influence the decision to grant a prudent discount to a firm contemplating exiting potentially extend well beyond the narrow impact upon transmission prices. For this reason, in our opinion, these are matters best left for central government, which can look at the issue from the perspective of the entire country, thereby taking into account these broader macroeconomic impacts, e.g., on employment, economic growth, and so on.

It is also important to remember that the government has a broader suite of policy mechanisms at its disposal to address any concerns about the ongoing viability of such businesses, such as subsidies funded by *all* taxpayers. These broad-based mechanisms are likely to be more effective tools through which to grant financial relief, since they would be even ‘broader-based’ than the PDP mechanism, reducing further the prospects of undesirable distortions.

For this reason, if there is a net benefit to “New Zealand Incorporated” from a party receiving financial relief, then it is reasonable to anticipate that this will be provided by the government without Transpower – or the EA – having to offer a discount.⁷⁵ In our opinion, this is the appropriate manner for such scenarios to be addressed. It would arguably be inappropriate for either Transpower or the EA to be arbitrating

⁷⁴ It is worth noting also that, in the specific case of Tiwai, should the smelter close, causing wholesale power prices to fall, this would affect the earnings potential of a number of power companies in which the government retains a sizeable shareholding. It was perhaps partly for this reason – as well as, no doubt, broader economic considerations – that Tiwai only recently received taxpayer funding when it was said to be considering exiting the market in the near-term. If that subsidy had not been granted, and Tiwai had exited, the government's returns from companies such as Meridian could well have decreased materially.

⁷⁵ For this reason, the \$10m included in the OGW CBA is arguably not relevant. If there is a net \$10m benefit to “New Zealand Incorporated” from a party receiving a subsidy, then it is reasonable to expect that this will be provided by the government under any form of the TPM.



such matters. Moreover, as we explain below, the practicability of the proposed reform is also questionable.

6.3.2 The proposal would be unworkable

One of the most important characteristics of the current PDP is that it limits Transpower's deliberations over prudent discounts to those matters over which it has experience – namely, those arising in the electricity market. In contrast, the proposal contemplates Transpower – or the EA – examining matters such as world aluminium or pulp and paper price forecasts. These are not areas in which they have any expertise.

In our opinion, it is not reasonable to expect either of these parties to make an informed assessment on these types of matters in determining the need for – and size of – a prudent discount. Moreover, it is not only the Tiwai smelter and Norske Skog that might apply for a prudent discount. Although these are the obvious candidates, any number of customers would be exposed to some degree to international markets and susceptible to adverse movements in world prices.

It would not be practicable for either the EA or Transpower to administer such discounts.

For example, the recent tribulations of New Zealand's dairy farmers have been widely reported. Collapsing global dairy prices have driven a large number of farmers into bankruptcy – or to the brink of it. If world dairy prices remain at those levels and farmers continue to lose money, there would seem to be no reason why a consortium of farmers (say, Federated Farmers) that were facing insolvency would – or should – be any less entitled than the smelter or Norske Skog to apply for a prudent discount.

Adjudicating upon prudent discount applications from the smelter and Norske Skog would be challenging enough, given the lack of expertise that Transpower and the EA have of the relevant markets. Acquiring expertise in the workings of every single world market in which New Zealand electricity customers participate would be infeasible. Yet, for the reasons set out above, that is what the proposal in the Issues Paper would potentially require.

6.4 Summary

To summarise, we agree that limiting the application of the residual charge to load is likely to be the best approach, if the proposal is implemented. However, the three capacity-based allocations that have been proposed might still give rise to distortions, could be viewed as 'unfair', and might not be the most efficient options available. Transpower should therefore be permitted to consider *all* potential allocation approaches. Finally, we do not consider that it is necessary or appropriate to extend prudent discounts to firms at risk of exiting. Such matters are best left to central government.



7. Assessment of the Oakley Greenwood cost-benefit analysis

The proposed changes to the transmission pricing methodology have been informed by a cost benefit analysis undertaken by Oakley Greenwood (the 'OGW CBA'). In this section we assess whether that model is fit-for-purpose. In particular, we:

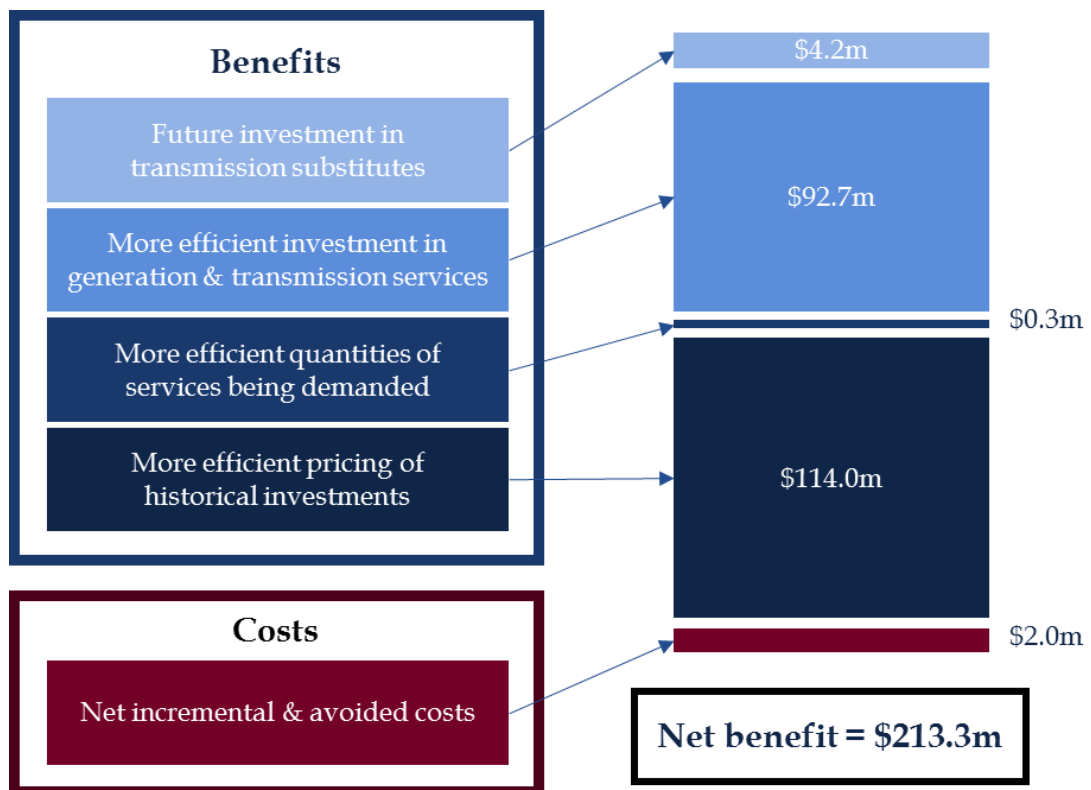
- examine the assumptions on which the model is predicated and assess whether they are reasonable; and
- provide our opinion as to the implications of our analysis for the validity of the CBA, and the conclusions that can be drawn from it.

We have also set out a more detailed description of the CBA model in Appendix B. We begin by summarising the overall results of the modelling and the net benefits that the proposal is estimated to yield.

7.1 Results of the CBA model

Figure 7.1: sets out a high-level summary of the results of OGW's CBA model for the preferred option, i.e., the AoB charge. Although this section focuses on the AoB related CBA modelling, our findings are equally valid to the modelling of the deeper connection charge.

Figure 7.1: OGW assessment of costs and benefits





Most of the estimated benefits come from more efficient investment in generation and transmission, and more efficient pricing of historical investments.

We note the following in respect of these results:

- The CBA estimates that the introduction of the AoB charge yields net benefits of \$213.3 million in present value terms.
- The CBA contemplates four broad classes of benefits, i.e.:
 - future investment in transmission substitutes;
 - more efficient investment in generation and transmission services;
 - more efficient quantities of services being demanded; and
 - benefits from more efficient pricing of historical investments.
- The CBA's estimated costs also yield a net benefit, because it is assumed that implementation of the AoB charge would lead to a significant reduction in future dispute costs.

The vast majority of the benefits estimated by the CBA come from more efficient investment in generation and transmission, and more efficient pricing of historical investments. Throughout this chapter we have confined our analysis to these benefits, because they are the principal drivers of the results.⁷⁶

7.2 Assumptions underpinning the CBA

By definition, a model is predicated on assumptions. There are three principal types of assumptions:

- **Foundational assumptions** – these are assumptions that influence the very foundation of the modelling exercise itself. In this particular case, they relate to the design and effect of the AoB (and deeper connection) charge.
- **Input assumptions** – these are the parameters that are the basis for the estimates made by the model. Inputs describe the specific circumstances, or scenarios, that the model investigates.
- **Logical and structural assumptions** – these assumptions relate to the manner in which the model *represents* (through formulae, calculations, and algorithms) the problem that the model seeks to solve. In this case, the problem is to estimate the costs and benefits of various transmission pricing proposals.

Appendix B contains a detailed description of the input assumptions, and the logical and structural assumptions that underpin the CBA. In the following section we set out a description of the foundational assumptions on which the CBA rests.

7.2.1 Foundational assumptions

There are three key foundational assumptions made throughout the CBA:

⁷⁶ For the avoidance of doubt, this should not be taken to mean that we agree with the approach that has been used to calculate the remaining benefits. We do not. For example, the \$300,000 in benefits said to arise from “more efficient quantities of the services being demanded” rests on the unreasonable assumption that there would be no deadweight loss arising from the higher energy prices. As we have explained already, that assumption is not reasonable.



The CBA rests on three foundational assumptions that do not hold.

- that the AoB charge would provide an efficient *ex-ante* price signal, i.e., that it would provide an accurate and predictable indication to customers of the potential consequences of their actions on Transpower's future costs;
- that the reallocation of costs – and resultant wealth transfers – that would occur under the proposal would not give rise to any allocative efficiency loss through inefficient reductions in demand; and
- that the AoB (and deeper connection) charges that each market participant (e.g., individual generators) would pay can be proxied by an estimate of the LRMC of transmission in each RCPD region, e.g., UNI, LNI, USI and LSI.

None of these assumptions hold, since:

- as we explained earlier, the implicit shadow price provided through the AoB charge would be an *inefficient* price signal that risks compromising static and dynamic efficiency;
- even if only a modest proportion of the additional costs that would be allocated to load customers were passed-through as volumetric charges, this would be likely to result in a significant allocative efficiency loss; and
- in any event, the individual AoB charges that each party will face will, by definition, *not* be equal to the LRMC of transmission in each RCPD region – this will be only true on average but, importantly, wrong in each individual case, which undermines a great deal of the modelling, because:⁷⁷
 - as we explain in more detail in following sections, several of the key benefits come from estimating revisions to forward-looking generation build schedules; and
 - if the estimates of the AoB charge that is added to the costs of each generation plant is wrong – which they will be – then there is no reason to think that those revised build schedules are accurate.

Further, by assuming that the AoB charges would be 'perfectly efficient' (i.e., send an efficient *ex-ante* price signal, and be non-distortionary *ex-post*), the model *must* conclude that future generation and transmission costs would be lower. In other words, the CBA starts by assuming that there will be a net benefit from introducing the AoB charge (and the deeper connection charge) and all it is then doing is determining its quantum.

This is not an appropriate approach to cost-benefit analysis. In order to provide meaningful assistance to a regulatory decision making process, a CBA must include modelling that represents the methodology that is being proposed and at least countenance the possibility of there being negative net benefits from implementing the proposal. The OGW CBA does not exhibit either of these essential properties. It

⁷⁷ This is highlighted by the fact that OGW uses the same approach to model the deeper connection – which is clearly completely different from the AoB charge. It does not make any sense for the AoB and deeper connection charges to yield exactly the same changes to forward-looking generation build schedules, given the obvious differences in those charging methodologies.



These unsound foundational assumptions render the CBA's results unreliable.

therefore cannot assist in informing whether the proposed methodology would be in the long-term interest of consumers – it *assumes* this, when it needs to *test* it.

It is worth noting that the CBA exhibits similar limitations to the analysis set out in the EA's first Issues Paper in 2012. The principal difference is that whereas the 2012 CBA abstracted away from *any* specific TPM proposal, the OGW CBA abstracts away from the methodology that has *actually been* proposed (substituting a simplified four-region LRMC option for the approach that is actually 'on the table', as it were). In neither case are the costs and benefits of the EA's proposal actually being assessed within the CBA.

The foundational assumptions of the CBA are consequently unsound which, in our opinion, renders its results unreliable. This conclusion is reinforced once the more specific assumptions and detailed implementation of the CBA are considered, as we explain in the following sections.

7.3 Assessment of the CBA model

The critical question is whether the model is fit for its intended purpose, i.e., to inform a decision to implement a substantial suite of changes to transmission pricing across the New Zealand power system. In our opinion it is not.

As we have just seen, the three key foundational assumptions underpinning the modelling are unsound, and subvert the fundamental purpose of cost-benefit analysis. But even setting aside these foundational problems, the more specific assumptions and detailed implementation of the CBA also render it unfit for its intended purpose. Our opinion is based on the following four findings:

Errors and unsound input assumptions render the CBA unfit for its intended purpose.

- the CBA itself has had to make a number of very strong assumptions in order to allocate transmission costs;
- the model is predicated on erroneous assumptions relating to the nature of the power system;
- options contemplated by the CBA are inherently unfavourable to the status quo, and so consequently overestimate benefits of the alternative options; and
- the CBA is likely to understate the costs of the proposal.

We explore each of these findings, in turn, in the following sections.

7.3.1 The CBA has had to make large assumptions to allocate costs

We describe in Appendix B that OGW assigns, or allocates, the system-wide estimate of growth capex to:

- generation and load; and
- geographic regions.

This allocation has been determined by a set of parameters provided by the EA. System-wide capex is allocated 60 per cent to load and 40 per cent to generation.



The CBA then applies the second set of cost allocation factors set out in Table 7.1 below.

Table 7.1: Annual capex allocations by generation/load and region

Generation or Load	Region	Allocation of annual capex (\$m)	Percentage share of annual capex
Generation	UNI	6.3	6.3%
	LNI	14.9	14.9%
	USI	0.7	0.7%
	LSI	18.0	18.0%
Load	UNI	30.1	30.1%
	LNI	17.0	17.0%
	USI	6.3	6.3%
	LSI	6.6	6.6%

Given that these values are critical to the calculation of the CBA's estimated benefits, Transpower requested additional information as to the basis of these parameters. In response, the EA has stated that:⁷⁸

'The 60:40 split between load and generation is an approximation. It reflects a high level understanding that economic investments benefit generation and load while reliability investments are of greater benefit to load. Given its broad approximation the Authority assessed the sensitivity of the CBA to changes in the load generation split.'

These annual allocations are approximations based on high-level assumptions.

And that:⁷⁹

'The allocation to regions for generation was based on GWh produced in each region. 2014 generation data was used. A simplified allocation method was applied here because of the difficulty of allocating the benefits of investments to specific generators (without running a tool such as vSPD to determine the beneficiaries for each assumed investment).'

In other words, it has not been possible to identify with any precision, the *cause* of the transmission costs, and who benefits from them. This is entirely understandable, and represents a fundamental and enduring challenge of setting prices for network services. The two statements set out above show that:⁸⁰

- it has not been possible to establish an 'efficient split of benefits' between generators and loads, and so it has been necessary to make a high-level approximation; and

⁷⁸ Email response from Electricity Authority to questions from Transpower, 7 July 2016.

⁷⁹ *Ibid.*

⁸⁰ We note that in a subsequent part of the CBA, capacity is the sole consideration and energy output is overlooked. This is a significant inconsistency in the approach.



- it has not been possible to determine how benefits of transmission should be allocated to generators, and so energy output has been used as an imperfect proxy for benefits.

Even though it has been unable to establish charge without these assumptions, the EA has stated that:⁸¹

As we have already seen, more complex modelling would not address this challenge.

'A simplified allocation method was applied here because of the difficulty of allocating the benefits of investments to specific generators (without running a tool such as vSPD to determine the beneficiaries for each assumed investment).'

In other words, the suggestion is that using sufficiently sophisticated modelling techniques – such as the vSPD method – to connect investments with beneficiaries will produce a more ‘accurate’ cost allocation. For the reasons that we set out above, that is unlikely to be the case, in practice.

The myriad uncertainties that arise in the estimation of private benefits over a 40- to 50-year period cannot be addressed by any amount of modelling and, as we have seen, more complexity means more cost. It is for this reason that we recommend simpler approaches be adopted if the AoB charge is implemented. The modelling in the CBA serves to reinforce the need for such pragmatism.

7.3.2 Erroneous assumptions as to the nature of the power system

We have identified the following errors in the representation of the power system in the model. First, the approach is driven solely by a capacity requirement, i.e., the requirement to build generation capacity to satisfy maximum demand. Put another way, the CBA does not represent half-hourly dispatch or variation in demand. Instead of representing the half-hourly dispatch process, the model tries to capture all of this information in a single variable: the LRMC of a specific project.

However, the model equates each generator’s average total cost (ATC), with the concept of a system-wide LRMC. These two concepts are not substitutes for one another. In this case, the ATC of an individual project is a poor predictor of whether that unit is the cheapest way to meet an increment in demand. For example, such an approach assumes that it will always be more efficient to build a peaking unit than an intermediate plant. In other words, the model does not represent the way in which new entry decisions are made, in practice.

Second, the modelling has not taken account of the constraints associated with hydro-electric plants (e.g., annual inflows, energy storage constraints, etc.), which is clearly relevant in a hydro-dominated system. The relevance here is that maximum demand is not the only factor that is likely to influence an investment decision.

Third, and in a similar vein, no adjustment has been made to account for the intermittency of wind generation. The results rely on an assumption that wind

⁸¹ Email response from Electricity Authority to questions from Transpower, 7 July 2016.



farms can be relied upon during peak demand to operate at 100 per cent capacity. In each case (i.e., for hydro plants and wind plants), the assumption is unrealistic, and render the estimate of benefits derived from the model's projected planning schedule unreliable.

Fourth, the calculation of benefits assumes that each plant generates according to its assumed capacity factor (e.g., Tauhara Stage 2 is assumed to generate at a capacity factor of 90 per cent). This assumption implies that once a generator has been constructed, it has a fixed future level of output and costs, *regardless of energy demand*. The implication of this assumption is that if an additional 1 MW of capacity is required to meet peak demand, then the model:

- will project that it is efficient to build a 240 MW CCGT to meet the additional 1MW of demand, i.e., far more than it needed; and
- will also assume that new generator runs 80 per cent of the time, i.e., because of the assumption relating to the capacity factor described above.

This is not a reasonable approach. It is akin to suggesting that the most sensible way for an airline to deal with a small increase in demand on a particular route would not be to add a single flight but, instead, to add ten new flights and then simply assume that they will have an 80 per cent load factor. Clearly, that would not be a sensible approach to route planning.

Fifth, the benefits that are said to arise from more efficient use of historical assets are assumed to arise primarily through avoiding an explosion in embedded diesel generation from customers seeking to avoid RCPD charges if the status quo remains in place. Currently, there is around 12MW of embedded diesel generation in New Zealand. The CBA assumes that this would increase by more than 4000% to 500MW if the RCPD charge is retained.

This assumption is based on an unsubstantiated assumption that all other forms of cheaper distributed generation have now been exhausted. In our opinion, the assumption that there will such an influx of embedded diesel plants is not credible.⁸² Although there could well be *some* additional diesel generation, a 40-fold increase is not a reasonable forecast.⁸³

There is also a large error in the calculation of the profitability of those hypothetical diesel plants. Although OGW notes that distributed generators would need to

Many key input assumptions do not accurately represent the power system, or the way that parties within it make decisions.

⁸² We note that this assumption is at odds with the analysis that Transpower undertook during its recent operational review. It estimated that increasing the number of periods over which contributions were measured from 12 to 100 in the LNI and LSI would reduce the amount of embedded diesel generation from 12MW to 0MW, i.e., render it uneconomic. This is clearly at odds with the CBA's assumption that there would be an enormous increase in the penetration of diesel plant with RCPD being measured over 100 periods. Transpower's CBA is available [here](#).

⁸³ To be clear, that is not to say that there would not be benefits from addressing any incentive problems arising under the current RCPD charge. It is simply to say that the CBA appears to have inflated the size of those benefits by assuming unreasonably that there would be a flood of the most expensive form of distributed generation. A further problem with the modelling is that, unlike the other aspects of the CBA, 100% weight is assigned to the 'Huntly Stays' scenario. The basis for this difference in approach is unclear.



operate for at least 200 periods in order to 'hit' the 100 peaks, this is inadvertently overlooked when the profitability of those units is calculated. Specifically, the model neglects to consider that there would be many periods where the plants would be running and incurring costs, but *not* during a peak period when they would receive 'avoided cost of transmission' payments.

In other words, the CBA overestimates both the likely level of new investment in embedded diesel generation *and* the profitability of those units. In our view, any investment in diesel generation would be on a much smaller scale, and a large portion of the investment that the CBA has modelled would not be profitable once the error described above was corrected. This would reduce substantially – and conceivably eliminate – the estimated benefit from removing the RCPD charge.

Finally, it is worth reiterating again that it is not plausible to suggest that around \$850m (in NPV terms over twenty years) in additional transmission charges could be allocated to load customers without there being at least some reduction in demand. If those additional transmission charges were passed-through even only *partly* as volumetric charges to end customers (i.e., if distribution businesses moved to more efficient pricing methodologies), and this caused even a small reduction in the use of existing assets, then the resulting allocative efficiency loss could be considerable and cannot simply be ignored.

We note that when Transpower sought to clarify the basis of many of these assumptions it was informed that, while they may not be realistic, their impact on the overall result was modest, because they would have an equivalent impact in all scenarios, i.e., with and without the proposal.⁸⁴ In our view, that is not a satisfactory response, for two reasons:

- it is not correct to suggest that these unsound assumptions would have the same impact in all modelled scenarios – their impacts could vary significantly across the different 'states of the world'; and
- even if that was not the case, if critical assumptions that do not reflect the power system that is supposedly being modelled do not affect the estimates of benefits, then that is symptomatic of grave problems with the methodology – almost by definition, the results *should not* be immune to such large errors.

In our opinion, any of these errors and unsound assumptions taken individually compromise the results of the CBA. Collectively, they render the analysis unfit for its intended purpose.

⁸⁴ Email response from Electricity Authority to questions from Transpower, 7 July 2016.



The CBA assumes incorrectly that many benefits would only be available under its modelled options and not the status quo.

7.3.3 Options contemplated are inherently unfavourable to the status quo

The largest single class of benefits arises from more efficient pricing of historical investments, accounting for \$114.0 million of the \$213.3 million of net benefits estimated by the CBA. Table 7.2 provides a breakdown of the specific components that make up this class of benefits, i.e.:

- the removal of the HVDC injection charge;
- replacement of the RCPD charge with a physical charge based on capacity; and
- introducing a more comprehensive PDP.

These benefits are identical for both options 1 and 2.

Table 7.2: Benefits from more efficient pricing of historical investments

Benefit	Options 1 & 2 (\$ million NPV terms)
Removing the HVDC injection charge	13.7
Replacement of the RCPD charge with a physical charge based on capacity	90.0
Introducing a more comprehensive PDP	10.3
Total	114.0

In addition to the various modelling errors described above, there is a more fundamental reason that the results are unsound. The critical point is that none of these benefits are uniquely attributable to the implementation of the AoB charge, or the deeper connection charge. The CBA incorrectly assumes that these benefits are not available under the status quo. In particular:

- the inefficiencies that are purported to arise from the RCPD and HVDC charges could be addressed through other means, e.g., through the introduction of an LRMC price with a non-distortionary residual charge; and
- as we explained in section 6.3, there is no reason to assume that the prudent discount policy is needed to prevent large users from exiting inefficiently – or that the proposed changes would be remotely practicable.

The \$114 million of estimated benefits from more efficient pricing of historical investments therefore arises simply from an inappropriate definition of the ‘counterfactual’. The CBA assumes that the only way to obtain the estimated benefits is through the options it models, when that is not the case.

7.3.4 The costs of the proposal have been understated

The CBA has not given appropriate consideration to the potential costs of the proposal. It assumes that there are avoided costs – in effect benefits – from reductions in future disputes. These avoided costs result in a saving that outweighs any incremental costs associated with designing and implementing the methodology. This does not seem reasonable, for two reasons:



- it assumes that substantive uncertainty will remain if the proposal is not implemented, when a more realistic scenario is that the current arrangements remain in place, but are no longer subject to uncertainty; and
- the inclusion of these benefits hinges on an assumption that the proposal would avoid disputes because the new approach is ‘well-documented and understood’ when, in our view, it is not, and would be likely to lead to *more* disputes.

The CBA has understated the potential costs of the proposal.

The CBA also does not include any estimate, or discussion of the potential costs that might arise from the proposal *reducing efficiency*. Rather, as we explained above, the CBA is predicated on the foundational assumption that there *cannot be* any costs in terms of reduced efficiency associated with changing the charging structure. For the reasons set out above, that assumption is inappropriate.

In particular, the shadow price that would be provided by the AoB charge would provide inefficient signals to load and generation that may compromise their consumption and investment decisions, leading to inefficiency. In addition, the CBA assumes that there would be no allocative efficiency loss from levying substantially more charges on load customers, which is not realistic.

7.3.5 Other unquantified benefits more likely to be costs

The Issues Paper states that the CBA’s \$213 million estimate of net benefits is ‘conservative’ because there are a number of other benefits that are more difficult to quantify. In our opinion, the additional benefits cited in the Issues Paper would either be immaterial or would be more likely to give rise to costs.

The other ‘unquantified benefits’ of the proposal are more likely to be costs.

First, it is unlikely that the proposal would have a beneficial effect on the new investment approval process. For the reasons we set out in section 4.3, the introduction of an AoB charging framework would either have no material effect on the approval process – and the investments that are made – or, worse, it could give rise to additional unconstructive opposition to *all* investments (including good investments), potentially *harming* dynamic efficiency.⁸⁵

Second, it is highly unlikely that the proposed methodology would give rise to fewer disputes, and reduce administrative costs. Rather, for the reasons set out earlier in this report, the opposite effect is altogether more likely. In particular, the regular identification of beneficiaries and ongoing scope for interventions such as optimisations and applications for prudent discounts will inevitably result in more disputes and sizeable increases in administrative costs.

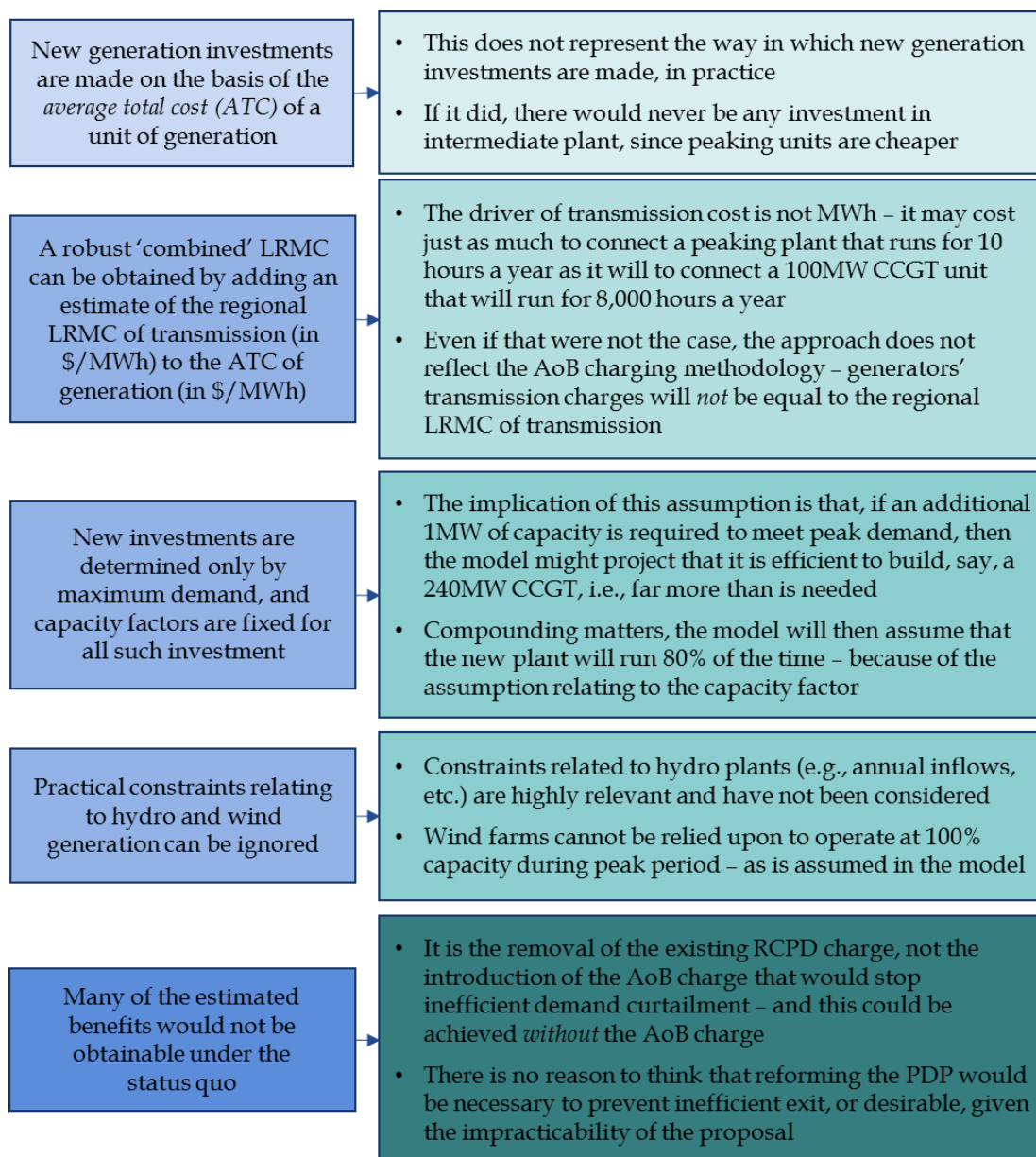
⁸⁵ We note in this respect that the Issues Paper refers in several places to a proposal to ‘underground’ Auckland’s transmission lines – and the costs that would be entailed with such an investment. In our view, this is an unnecessary distraction. Transpower would never propose such an investment and, even if it did, the Commission would not approve it. The AoB charge would therefore not ‘make the difference’ between such investments proceeding – they would not occur under any plausible state of the world.

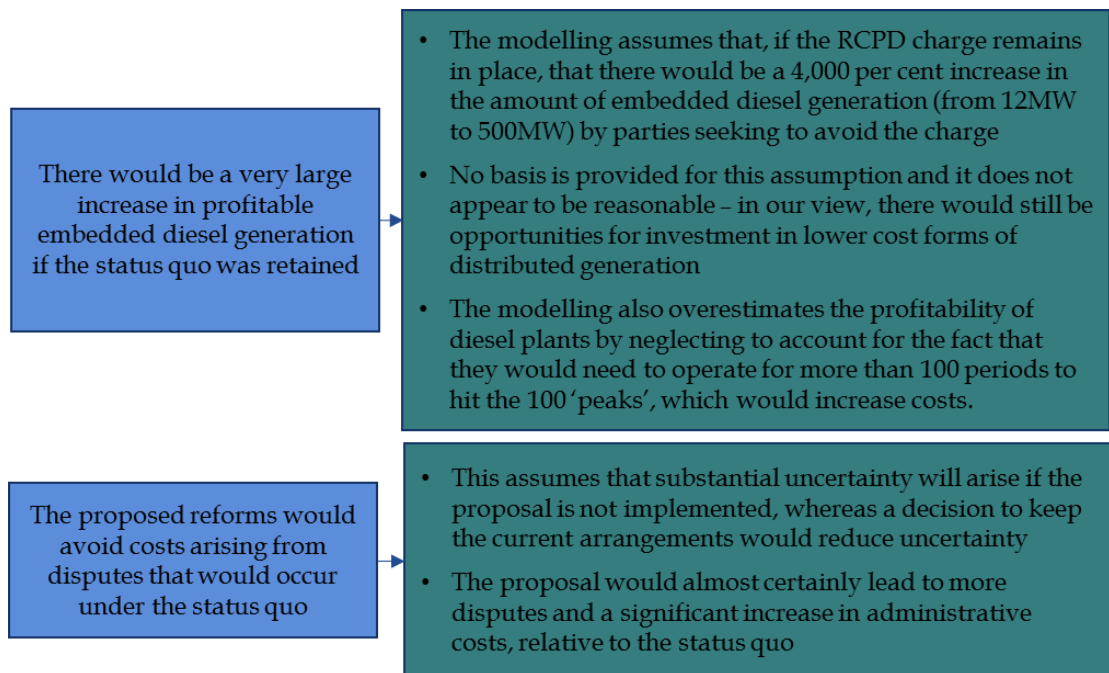


7.4 Summary

The CBA is not fit for its intended purpose, because OGW has not quantified the costs and benefits of the proposals to the extent practicable. The modelling does not reflect accurately the AoB charge methodology (including its inefficiencies), the way in which the electricity system functions or the manner in which its participants make decisions. It also contains numerous errors, as Figure 7.2 illustrates.

Figure 7.2: Key input assumptions underpinning the OGW CBA





It follows that no weight can be placed on the resulting estimates of benefits and the analysis cannot provide any insight into whether to reform the TPM in the manner contemplated. Furthermore, the various other 'unquantified' benefits identified in the Issues Paper would not be material – and, in most cases, would not be positive.



Appendix A Efficient price signals

The Issues Paper quite rightly points out that efficient transmission pricing requires customers to be made aware of the consequences of their actions on Transpower's *future costs before* they are incurred. In competitive markets, these price signals are provided through market forces, which signal to customers *both* the short- and long-run marginal cost of supply. However, as we explain below, the same cannot be said in the case of transmission services.

A.1 Price signals in competitive markets

In a competitive market, efficient signals are delivered to buyers and sellers through the market price. In the short-run, capacity is fixed, and so 'surpluses' and 'shortages' are managed by increasing or decreasing the price of the existing capacity to signal the current short-run marginal cost (SRMC).⁸⁶ For example, in the short-run, the number of hotel rooms in Auckland is fixed. The most efficient way to deal with short-term excess demand during peak periods (e.g., around New Year's Eve) is therefore to increase the price of existing rooms to curtail demand, since:⁸⁷

- it is simply not possible to construct a hotel in that timeframe, e.g., to find a site, obtain planning approvals, arrange financing, undertake construction, and so on – the number of room is fixed in the short-run; and
- those investment decisions will not be based solely on one period of high prices in any event – rather, it is the expected returns over a longer time horizon that are relevant for entry/expansion decisions.

However, if demand grows to the point where prices are *constantly* increasing to curtail demand (i.e., repeatedly throughout the year) then it may be more efficient to build more rooms. In other words, in competitive markets, a 'tipping point' will occur at which the expected cost of *curtailing* demand (as represented by the SRMC) increases beyond the cost of expanding capacity to *meet* that demand – either via new firms entering, or existing suppliers augmenting capacity. At that point, new investment will take place.

Specifically, as Green *et al* (2011) explain,⁸⁸ in the long-run, once firms in competitive markets have had time to expand or reduce their capacity, one would not expect to see SRMC-based prices that are significantly and persistently above the *long-run marginal cost* (LRMC) of adding capacity, or below the *long-run avoidable cost* (LRAC)

⁸⁶ Note that an important distinguishing feature of SRMC is that, in the event existing capacity is insufficient to meet all demand, SRMC is represented by whatever level is necessary to curtail demand to match available supply. It therefore takes account of the costs of shortages faced by customers.

⁸⁷ Equally, existing hotels are not going to respond by adding more rooms. Conversely, an existing hotel chain that experienced a temporary period of low prices due to reduced demand is unlikely to respond in the near term by reducing its number of rooms or by exiting the market.

⁸⁸ Green *et al*, *Potential Generator Market Power in the NEM, A Report for the AEMC*, 22 June 2011.



associated with reducing capacity. In other words, in the long run, in competitive markets, prices should equal both SRMC *and* LRMC.

The market dynamics described above can promote various forms of desirable economic efficiency. First, it can encourage short-term 'static' 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 shares, and to earn producer surplus, thereby promoting productive efficiency. It can also enhance allocative efficiency, since:

- in the short-run (and the long-run), the prevailing price will reflect the costs of production (the SRMC) of the 'marginal producer', which will incentivise efficient near term consumption decisions;
- consumers will only demand a product when the private benefits that they receive from consuming it (i.e., their consumer surplus) is positive, i.e., when their willingness to pay exceeds the market price; and
- 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 profits, i.e., they will chase 'producer surplus'.

Second, competition will promote dynamic efficiency. In particular, if prevailing market prices are seen to be persistently above the LRMC of adding new capacity (i.e., if the 'tipping point' is reached), this will encourage efficient new investment by new entrants or existing suppliers, as they seek to expand supply and 'chase' the profits on offer. Similarly, those firms that cannot compete effectively at the prevailing market price (i.e., because it is below their LRAC) will efficiently divert their resources to more productive endeavours in other markets.

An especially important feature of competitive markets is that these sources of efficiency are obtained through cost-reflective price signals that are delivered *in real time* – or *ex-ante*. Consumers and producers alike can look at the prevailing market price and made informed decisions about the actions that are most likely to promote their own private benefit. Most notably:

- a consumer can look at the prevailing market price and determine whether it is greater or less than she is willing to pay (given her other options), i.e., she can look at the price and make a decision that immediately maximises her private benefit (her consumer surplus); and
- a producer can look at the market price to see whether it is more or less than the LRMC of adding new capacity or the LRAC of reducing capacity (as the case may be), and then decide how best to deploy its resources, i.e., whether to invest in that market, or to divert its finances elsewhere.

Furthermore, in each case, the pay-off for the consumer or producer is self-evident, since they are signalled clearly through the market price. The attainment of those benefits also does not depend on the actions of other parties, e.g., if it is not beneficial for a consumer to buy a product, the obtainment of that benefit does not depend upon, say, other consumers not buying it too. This also serves to promote static and dynamic efficiency.



A.2 Application to transmission services

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

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

The full nodal pricing arrangements in the wholesale market mean that the difference in spot prices between nodes should reflect this SRMC of transmission, irrespective of whether constraints exist. The ‘unit price’ of transmission therefore reflects the ‘short-term’ market like outcome described above, i.e., it reflects the SRMC of using the existing assets. Moreover, because competing offers provide incentives for generators to bid at their SRMC, demand at each node is typically served at the lowest possible cost.

In other words, as the Issues Paper observes,⁸⁹ the nodal pricing and dynamic loss factor regimes are reasonably efficient at coordinating use of the existing grid, i.e., they produce a relatively high degree of short-term static efficiency. The initial thinking in New Zealand was that the existence of full nodal pricing might also give rise to efficient market-driven investments, i.e., to *dynamic* efficiency. The theory was that, when confronted with the escalating costs of losses and constraints, network users would invest in new transmission assets; namely:

- users would invest in new transmission capacity when the LRMC of doing so was less than the projected SRMC of future losses and congestion; and
- in return, they would receive a right⁹⁰ to any congestion rents, i.e., revenue that arises from a divergence in the spot price between locations.

In other words, it was expected that, if left to their own devices, grid users would abide by the ‘optimal investment rule’ that is seen to operate in workably competitive markets, described above. Namely, investment would occur when the theoretically efficient ‘tipping point’ was reached, i.e., where the expected cost of *curtailing* demand (i.e., the SRMC of losses and congestion) increased beyond the

⁸⁹ Issues Paper, §5.70.

⁹⁰ Such rights might be “physical rights” to the dedicated infrastructure, or “financial” transmission rights (FTRs) that are purely financial in nature.



cost of expanding the existing transmission capacity to *meet* that demand (i.e., the LRMC of adding capacity).

We now know that thinking was misguided because it failed to account for a number of important practical challenges with the application of market-based principles in the context of transmission. One of the biggest problems is that the theory did not recognise that, unlike in a competitive market, the average of the SRMC of transmission over time will virtually always be lower than the LRMC of adding capacity. As Fraser (2002) explains:⁹¹

- the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices are capped below the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the network;
- the business of transmission is very complicated and unpredictable, so transmission planners justifiably and efficiently ‘err on the side of caution’ when investing in new capacity – building sooner rather than later, and transmission planners also use reliability standards (e.g., the N-1 deterministic standard for the core grid) that are independent of economic costs;
- market power problems may lead to overbuilding transmission in an attempt to promote competition generally in power markets and there are valid national security reasons to build too much transmission; and
- the result of economies of scale in electricity transmission is that spare capacity is common, which reduces SRMC below LRMC, i.e., it is impossible to match transmission capacity precisely with transmission requirements at all times.

Unlike the ‘hotel business’ scenario described earlier, new transmission assets will continue to be built – for good reasons – before being justified by short-run congestion and losses savings alone. Put another way, the locational price differences between ‘locations A and B’ will almost always be lower than the long-run cost of building transmission between those two places.

Although nodal prices will reflect the SRMC of the supply using the existing infrastructure, they will often *never signal the LRMC* of adding capacity because they will not reach that level. Nodal prices and losses therefore cannot be relied upon to provide efficient signals to grid users of the costs that Transpower will incur when it replaces or upgrades its assets. As Figure 2.1 illustrates, those price signals will be *too weak*.

There is therefore a ‘missing’ price signal. In the absence of some other additional price signal, today’s grid users will not factor into their consumption and investment decisions the potential consequences for Transpower’s long-run investment costs. This can be expected to compromise dynamic efficiency. By way of simple example:

⁹¹ H. Fraser, ‘Can FERC’s Standard Market Design Work in Large RTOs?’, *Electricity Journal*, Volume 15, Number 6, July 2002, p.25.



- a load customer may decide not to curtail its demand in a peak period in response to a higher nodal price (e.g., a 'higher' SRMC), but that incremental demand may 'bring forward' the need to undertake new investment; and
- because of the practical factors described above, that new investment will take place before nodal prices reflect the LRMC of that investment, in which case the load customer would *never see* the 'true costs' of its actions.

It follows that, in order for customers to be made aware of the consequences of their actions on Transpower's *future costs before* they are incurred, something beyond the signal provided by nodal prices and losses is needed. Put simply, an additional signal is required that conveys to customers in some way the 'gap' that exists between the SMRC and LRMC of transmission.



Appendix B Oakley Greenwood modelling

The OGW CBA modelling is relatively complex, in that it involves numerous steps, and has been implemented in several different spreadsheets. Examination of the values and formulae in spreadsheets does not aid in understanding the concepts that they embody. With this in mind, in this appendix we focus on explaining the overarching structure of the model, because it assists in identifying how a specific input, assumption or component influences the results.

B.1 Options and scenarios contemplated by the CBA

This section describes the options and scenarios contemplated by the CBA.

B.1.1 Options

OGW has compared the costs and benefits of two options versus the status quo, i.e.:

- Option 1: Deeper connection-based charge.
- Option 2: Area of Benefit charge.

As noted in section 7 OGW has not, in fact, modelled an AoB charge for option 2 but, rather, a form of regional LRMC charge. As a result, we question whether the CBA is assessing the correct proposal. In addition, we described in section 7.3.3 that the construction of these options is inherently unfavourable to the status quo, and so will tend to inflate any estimated benefits of the options.

B.1.2 Scenarios

The CBA results are based on two distinct scenarios, i.e.:

- **Huntly stays (or Huntly is retained) scenario** – assumes the Rankine units at Huntly power station remain in operation.
- **Huntly leaves (or Huntly is not retained) scenario** – assumes the Rankine units at Huntly power station are retired from operation.

The CBA combines the results of the two scenarios into a single result, by averaging the benefits from the two scenarios.

B.2 Estimation of benefits

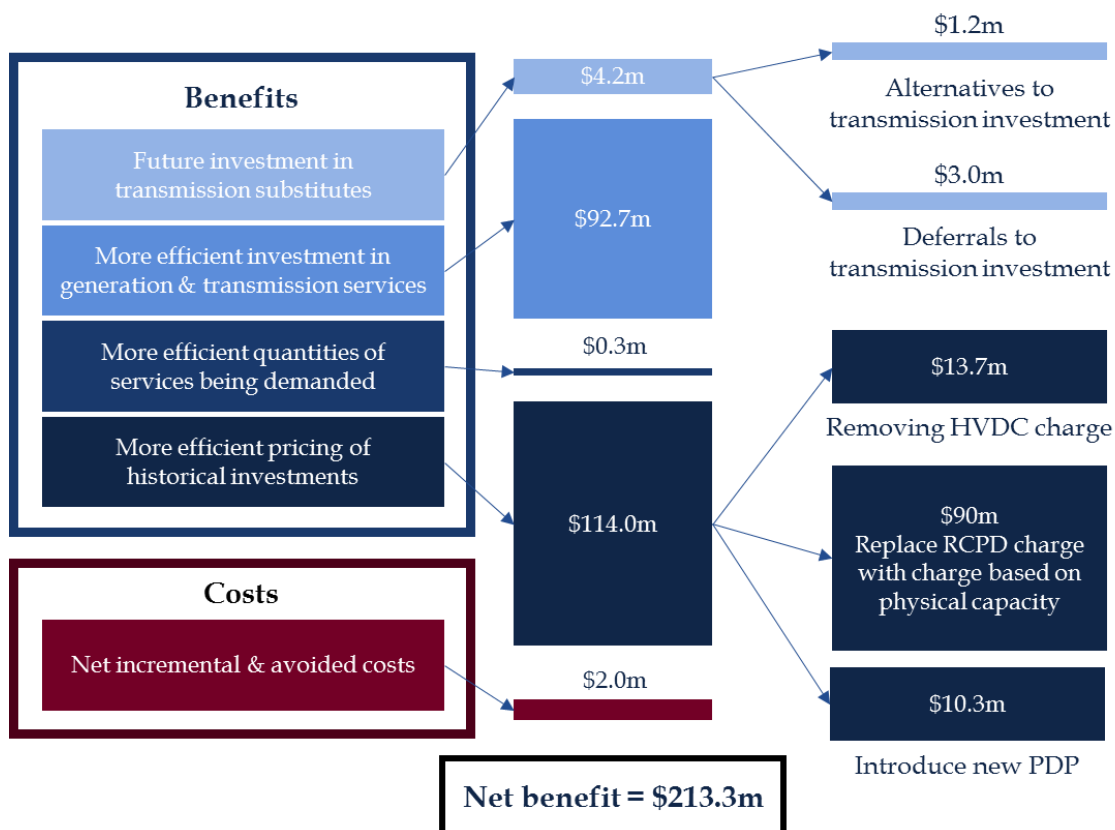
The OGW CBA seeks to estimate four classes of benefits:

1. Future investment in transmission substitutes.
2. More efficient investment in generation and transmission services.
3. More efficient quantities of services being demanded.
4. Benefit from more efficient pricing of historical investments.



Figure B.1 breaks down the estimated benefits for the AoB charge options. We also include the estimated costs, because these also yield a net benefit.

Figure B.1: CBA assessment of costs and benefits for AoB charge



B.2.1 More efficient investment in generation and transmission

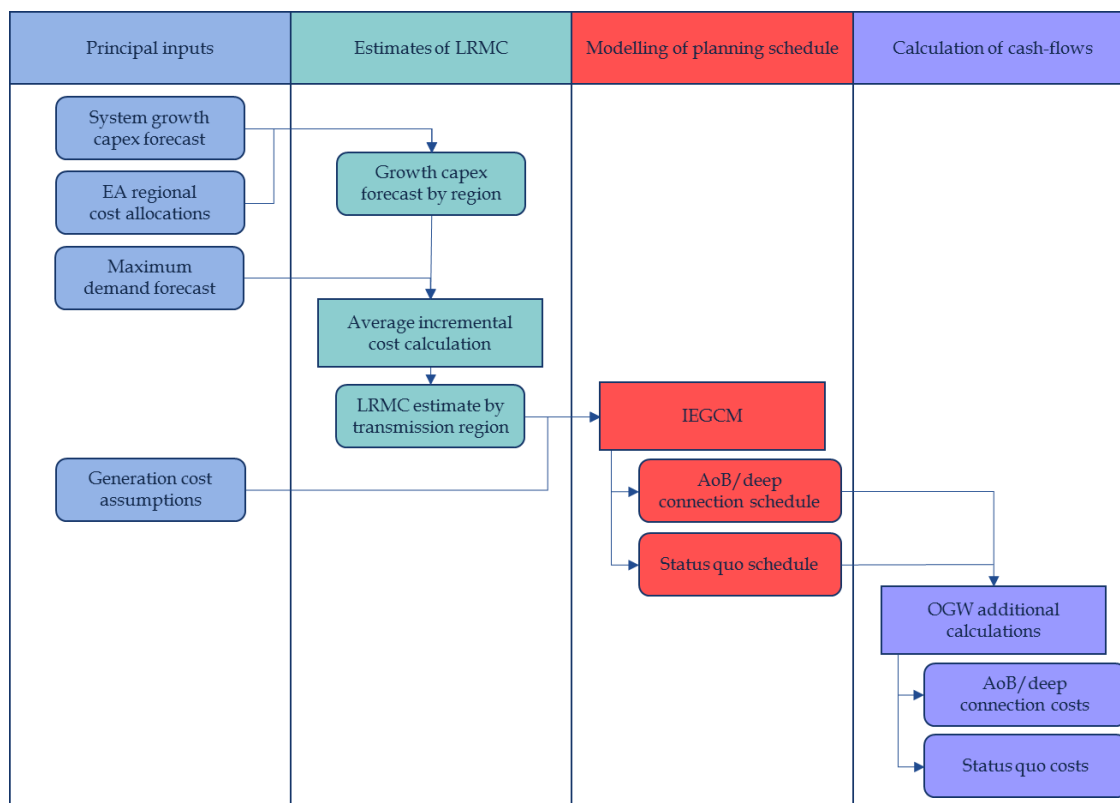
It is helpful to decompose the different elements of the OGW model into the following four parts, or steps, i.e.:

- **Principal inputs** – this part of the model consists of the input assumptions, or parameters, that feed into the calculations later in the model.
- **Estimation of LRMC** – this part of the model estimates LRMC for each of the four RCPD regions using an average incremental cost (AIC) approach.
- **Modelling of the Planning Schedule** – using a set of generation cost assumptions, and the estimates of LRMC, this part of the model uses the Interactive Electricity Generation Cost Model (IEGCM) to produce two project schedules:
 - one **including** the LRMC estimate of transmission in the IEGCM, and so representing the AoB/deeper connection charge; and
 - one **excluding** the LRMC estimate of transmission in the IEGCM, and so representing the Status Quo Schedule.
- **Calculation of Cash flows** – the final part of the model calculates a series of cash flows associated with each project schedule (i.e., transmission and generation costs).



Figure B.2 provides a graphical representation of the critical components of the OGW approach to estimating the benefits from more efficient investment in generation and transmission.

Figure B.2: Modelling more efficient investment in generation and transmission



B.2.1.1 Principal Inputs

There are four principal inputs to this part of the model.

System wide demand-driven capex forecasts

The CBA assumptions for system wide demand-driven capex are as follows:

- **Huntly Stays scenario** – \$100 million per annum for the next 30 years.
- **Huntly Leaves scenario** – \$100 million per annum, save for a period of 5 years (years 3 to 7 inclusion) where capex increases to \$200 million per annum.

These assumptions were provided by the EA.

This input is described in the model as ‘demand-driven’ capital expenditure, which we assume means that the capital expenditure would not be required *but for growth in demand*. Put another way, we assume that ‘demand-driven’ capital expenditure excludes investment to replace existing transmission assets.

Cost allocation factors

The CBA model assigns, or allocates, the system-wide estimate of growth capex to:



- generation and load, i.e., presumably capital expenditure that is deemed to be related to growth in generation or load, respectively; and
- geographic regions, i.e., presumably the location where the growth in generation or load is leading to a need for transmission investment.

This allocation is determined by a set of parameters have been provided to OGW by the EA. System-wide capex is allocated 60 per cent to load and 40 per cent to generation. OGW then applies the second set of cost allocation factors set out in Table B.1.

Table B.1: Cost allocation factors

Generation or Load	Region	EA Allocation Factors
Generation	UNI	15.8%
	LNI	37.2%
	USI	1.8%
	LSI	45.1%
Load	UNI	50.2%
	LNI	28.3%
	USI	10.5%
	LSI	11.0%

Applying these cost allocation factors yields the annual capex allocations by generation/load and region set out in Table B.2 below.

Table B.2: Annual capex allocations broken down by generation/load and region

Generation or Load	Region	Allocation of annual capex (\$m)	Percentage share of annual capex
Generation	UNI	6.3	6.3%
	LNI	14.9	14.9%
	USI	0.7	0.7%
	LSI	18.0	18.0%
Load	UNI	30.1	30.1%
	LNI	17.0	17.0%
	USI	6.3	6.3%
	LSI	6.6	6.6%

It is critical to observe that once the system-wide growth capex has been assumed, the allocation parameters *determine* the capex by region.



Transpower requested additional information as to the basis of these parameters. In response, the EA stated that:⁹²

- the 60:40 split is an approximation, based on its 'high level understanding' of the different types of investments; and
- the allocation of capex to regions for generation was based on energy (in GWh) produced in each region – the EA stated that it would have been more difficult to allocate costs to specific generators using, say, the vSPD model.

Note that the model does not allocate the sunk costs of any existing investments to load or generation – despite the fact that there are a number earmarked for the AoB charge. Similarly, the model does not allocate any future costs that are not growth related, e.g., replacement expenditure. Again, these would be charged to load and generation under the proposed AoB charge.

The consequence of this is that the costs allocated to generators in each region under the model do not represent all of the potential charges that those parties would potentially be facing under the methodology, as proposed. In other words, this is another key point of difference between the approach that is set out in the Issues Paper, and the methodology that is modelled in the CBA.

Forecasts of maximum demand and growth in maximum demand

The CBA model uses two different sets of inputs that relate to forecasts of maximum demand:

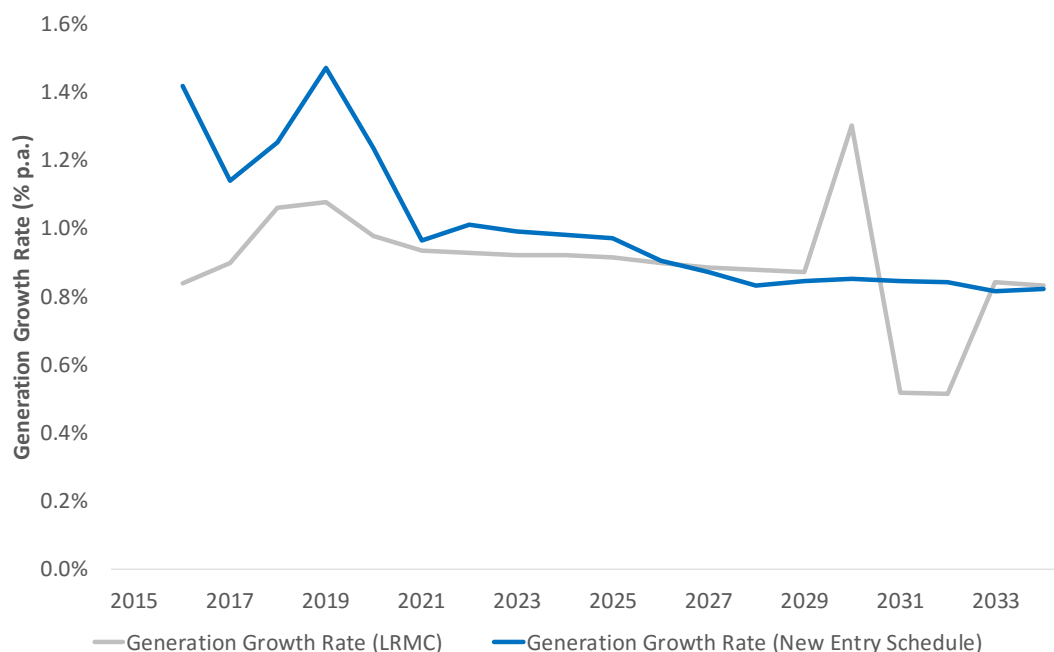
- **For the purpose of estimating LRMC**, the CBA assumes that generation capacity increases at an annual rate, derived from forecast increases in annual maximum demand across the whole New Zealand system. Put another way, the CBA assumes that supply (i.e., generation) increases at the same rate as demand (i.e., maximum demand).
- **For the purpose of estimating new entry of generation**, the CBA assumes that generation capacity increases at a different rate, referred to in the model as the 'estimated growth rate'. The source for this growth rate cannot be determined from the model, but it is generally higher than the growth rate used for the purpose of estimating the LRMC.

Figure B.3 sets out OGW's assumed growth rate for maximum demand, and the resultant forecast of generation capacity.

⁹² Email response from Electricity Authority to questions from Transpower, 7 July 2016.



Figure B.3: Summary of assumptions related to maximum demand



The difference between the two sets of assumptions is relatively small, and only results in an additional 200MW of generation capacity over the 20-year modelling horizon. Nevertheless, that the model contains two different sets of assumptions for a single input appears to be an error.

Generation cost and prospective new-entrant plant assumptions

The approach taken for this part of the CBA involves creating a list of prospective, new-entrant generation facilities. OGW has sourced its list of prospective facilities from the Interactive Electricity Generation Cost Model (hereafter referred to as the IEGCM), which is published by the Ministry of Business, Innovation & Employment.

The IEGCM contains a list of 46 prospective facilities. OGW has removed the Otahuhu C facility from this list, and used the remaining 45 facilities in its analysis, together with the attendant cost assumptions set out in the IEGCM, including:

- a fuel, or technology type (e.g., geothermal, wind, CCGT);
- a registered capacity (expressed in MW);
- a level of 'typical' generation per annum (expressed in GWh);
- capital, variable operations and maintenance, and fixed operations and maintenance costs; and
- the resultant estimates of LRMC that are produced by the IEGCM.

Figure B.4 sets out a list of the prospective projects included in the CBA modelling, ordered by their LRMC, and coloured according to technology type. A critical observation is that many of the facilities are wind farms.



Figure B.4: OGW list of prospective new-entrant facilities ordered by LRMC

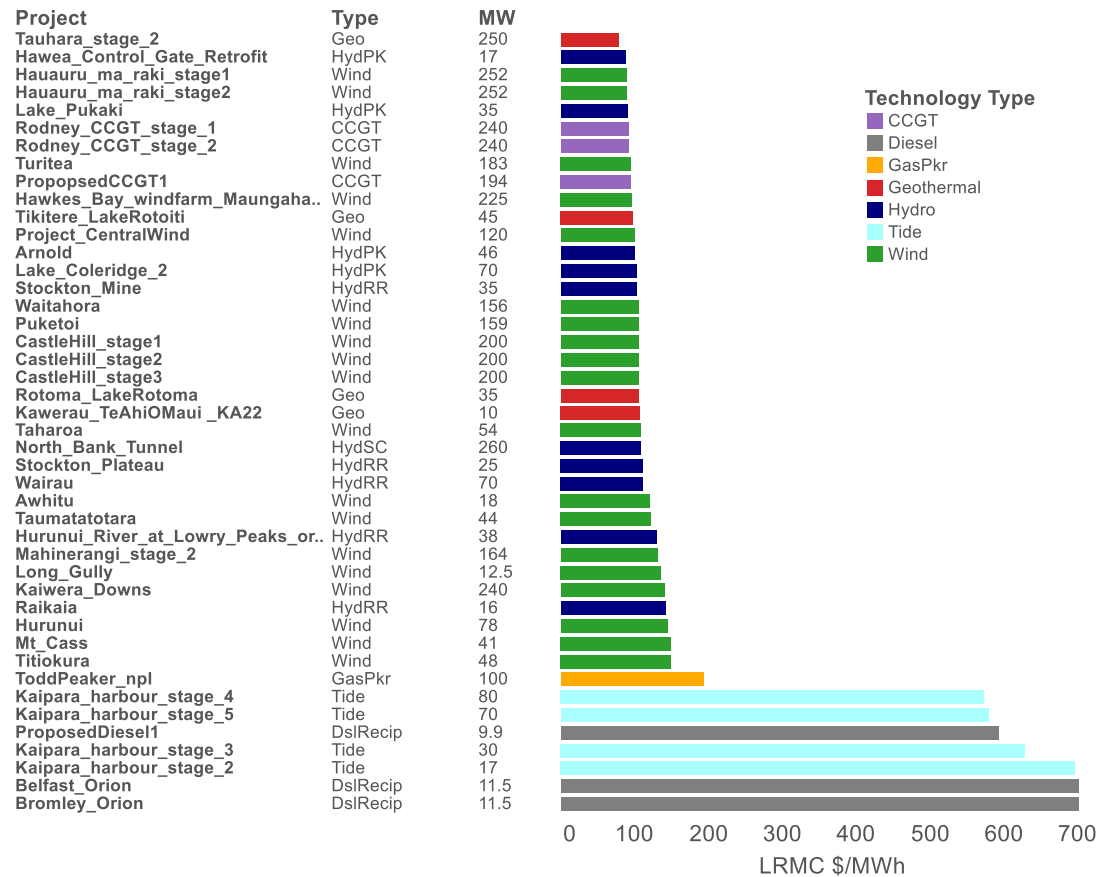


Figure B.4 shows an ordering on the basis of the 'LRMC of generation'. However, we note that the CBA *does not measure the LRMC of generation* – the values in Figure B.4 are instead estimates of the *average total cost* of a new unit of generation under a range of assumptions.

B.2.1.2 Estimates of LRMC

This part of the model estimates the LRMC of providing transmission services to generation.⁹³ OGW has applied an average incremental cost approach to estimate the LRMC of providing transmission services to generation. This is achieved using the following formula:

$$LRMC \text{ [\$ per MW \cdot year of generation]} = \frac{PV(\text{Generation Tx. Expenditure})[\$]}{PV(\text{Incremental Generation})[MW \cdot year]}$$

OGW has also calculated, or expressed, the LRMC of providing transmission services to generation in dollars per MWh terms using the formula:

$$LRMC \text{ [\$ per MWh of Generation]} = \frac{PV(\text{Generation Tx. Expenditure})[\$]}{PV(\text{Incremental Generation})[MWh]}$$

⁹³ We note the distinction between the three different concepts of LRMC in the CBA, i.e., the LRMC: of providing transmission services to loads, referred to as 'load LRMC'; of providing transmission services to generation, referred to as 'generation LRMC'; and of generation of energy, referred to in CBA as LRMC (\$/MWh).



It is important to distinguish between these two estimates of LRMC, one expressed in terms of energy and another expressed in terms of capacity. Although they use similar inputs, they are not the same.

The cost of providing transmission services (whether it be to generation or load) is driven by the capacity requirement in the network (typically expressed in MW or MVA years). There is therefore a clear, *causal* relationship between a change in maximum demand and the costs imposed on the network. In contrast, an increase in energy throughput has only an *association* with costs imposed on the network.

Table B.3 compares the CBA estimates of LRMC, expressed on both bases. This part of the model only uses the estimates of LRMC expressed in dollars per MWh.

Table B.3: Estimates of LRMC in the OGW model

Scenario	Region	LRMC (\$ per MW year)	LRMC (\$ per MWh)
Huntly Stays	UNI	35,949	6.59
	LNI	48,859	8.41
	USI	23,678	5.41
	LSI	51,301	11.71
	System	46,355	9.08
Huntly Leaves	UNI	68,142	14.56
	LNI	67,668	11.65
	USI	32,793	7.49
	LSI	71,049	16.22
	System	67,929	13.69

Differences in LRMC depending on scenario

An important point to observe is the difference in estimates of LRMC for the two scenarios (Huntly Stays, versus Huntly leaves), which is a result of:

- the higher transmission capex for the Huntly Leaves scenario (i.e., NPV of \$532.0 million versus \$384.1 million); and
- lower assumed incremental generation in the Huntly Leaves scenario (e.g., NPV of 27.2 GWh versus 29.6 GWh), due to the exclusion of generation from Huntly in OGW's calculations.

We have described the differences in the CBA assumptions for transmission capex in the two scenarios. Specifically, the model assumes that generators throughout the country are allocated a fixed share of those incremental transmission costs. Note that yields the clearly counterintuitive outcome in which generators locating in the UNI – where more generation would presumably be desirable – also pay higher transmission charges.

The second point is also important to understand, i.e., the difference in assumed incremental generation between the two scenarios. We have described the CBA



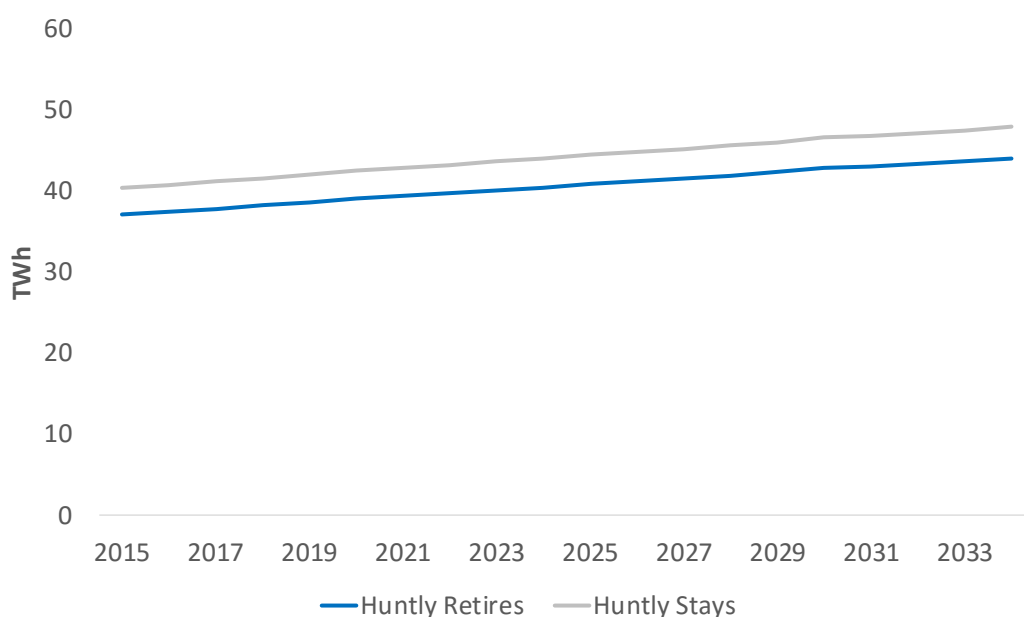
assumptions about generation growth rates (see above). As we have already seen, the generation growth rates assumed in the CBA do not vary according to scenario.

But OGW has nevertheless reduced the generation volumes in the Huntly Leaves scenario by a quantity equal to the output from Huntly's two units. Figure B.5: compares the resultant generation volumes for the two scenarios. We do not see that there is a basis for changing the quantity of *system-wide* generation. Such an assumption is equivalent to suggesting either that, under the 'Huntly Leaves' scenario:

- the generation output that is 'lost' from Huntly would not be replaced by generation anywhere else; and
- load will be shed, or that energy will be rationed because of that permanent reduction in generation.

These assumptions are not reasonable. Moreover, if they were, then the costs that would be associated with the necessary load shedding would need to be accounted for in the CBA. Currently, they are not.

Figure B.5: OGW assumed generation by Scenario for estimation of LRMC



B.2.1.3 Modelling of the project schedule

This part of the model seeks to forecast, or project, schedules of new generation projects that will be constructed in the future. The process involves three steps:

- using the IEGCM to determine the LRMC of generation for each proposed new-entrant plant;



- preparing two lists of new generation projects, ordered according to their assumed LRMC of generation (expressed in \$ per MWh),⁹⁴ i.e.:
 - the **old case** where the projects are ordered according to OGW's estimated LRMC of generation; and
 - the **new case** where the projects are ordered according to OGW's estimated LRMC of generation **plus** OGW's estimate of LRMC of providing transmission services to generation in that region; and
- identifying a schedule of projects that are constructed to meet projected growth in maximum demand, where the projects with the lowest LRMC (including or excluding transmission) are constructed first.

Based on the information that has been made available, it appears that OGW has identified when projects will occur manually. Put another way, it has 'eye-balled' the level of maximum demand, and manually selected the projects that will be required to meet this value. This is an unusual approach to modelling future generation projects, and has the consequence that it is not possible to alter inputs to its models, and see the resultant change in projected benefits.

Figure B.6 and Figure B.7 show OGW's projected old and new project schedules, for the Huntly Stays and Huntly Leaves scenarios respectively.

Figure B.6: Old and new project schedules – Huntly Stays Scenario

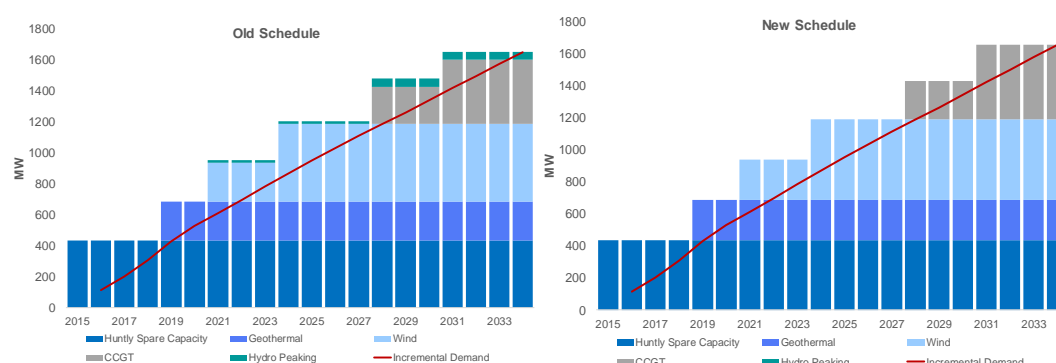
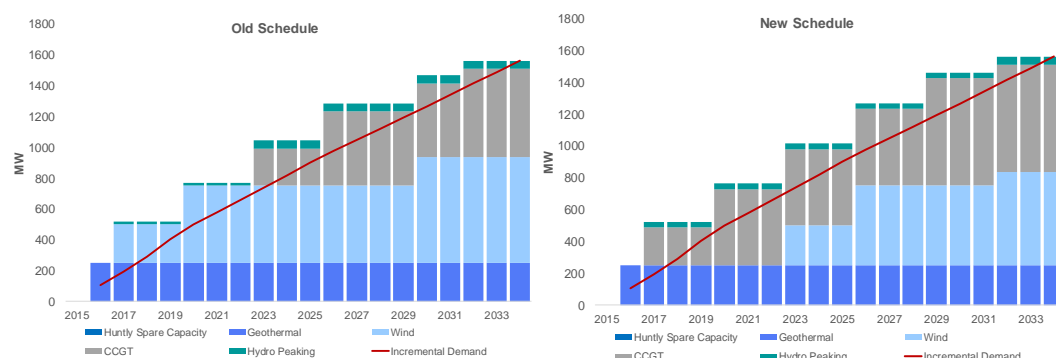


Figure B.7: Old and new project schedules – Huntly Leaves Scenario



⁹⁴ We have described that OGW has in fact estimated the average total cost of a unit of generation. However, to avoid confusion we have adopted its convention throughout this section.



B.2.1.4 Calculation of cash flows

The final step in the estimation of benefits from more efficient investment in transmission and generation is to calculate the cash flows arising from each project schedule. To do so, the model assumes that:

- all capex is incurred upfront, in the year prior to the generation capacity is required;
- variable operations and maintenance, fixed operations and maintenance, and transmission costs are incurred every year *after* the capacity of the plant becomes available; and
- each plant generates according to its assumed capacity factor (e.g., Tauhara Stage 2 is assumed to generate at a capacity factor of 90 per cent), and used this value to project variable operations and maintenance costs and transmission costs.

The first two assumptions appear to be a simple error – it does not make sense that capacity is available to meet growth in demand without there being operations and maintenance, or transmission costs associated with that capacity.

The third assumption implies that once a generator is constructed it has a fixed future level of output, and so costs, *regardless of energy demand*. For example, if an additional 1 MW of capacity is required to meet peak demand, the OGW model will not only project that it is efficient to build a 240 MW CCGT to meet the additional demand, but will also assume that new generator runs 80 per cent of the time. This is not a reasonable approach.

B.2.2 More efficient pricing of historical investments

This category of benefits comprises the following three parts:

- Benefits from the removal of the HVDC injection charge.
- Benefits from replacement of the RCPD charge with a physical charge based on capacity.
- Benefits from introducing a more comprehensive PDP.

We describe the CBA's approach to estimating these benefits below.

B.2.3 Benefits from the removal of the HVDC injection charge

We have not been able to review the modelling of these benefits in detail, because the 'SIMI Model' referred to in the CBA model has not been made available. Nevertheless, the OGW report has described the modelling of these benefits in sufficient detail for us to provide comment on their approach, and findings.

OGW's report states that it has estimated benefits from removal of the HVDC South Island Mean Injection (SIMI) charge using a similar approach as that used to model benefits from more efficient investment in generation and transmission (see our description in section B.2.1).



Once again, the estimated benefits arise from comparing the cash flows for two different project schedules. In this case, the two project schedules arise from assuming that:

- an HVDC SIMI charge is applied to South Island Generators; and
- an HVDC SIMI charge is not applied to South Island Generators.

OGW's methodology demands that the HVDC SIMI charge be converted into a figure expressed in dollars per MWh. To do so, OGW has relied on an estimate of this value previously developed by Scientia consulting.⁹⁵

OGW has estimated the benefits from removal of the HVDC injection charge using a virtually identical model to that used to estimate benefits from more efficient investment in generation and transmission. We have demonstrated that this model contains a number of errors. For that reason, we do not consider that any weight can be placed on the resulting estimates of benefits.

Furthermore, as we have described in section 7.3.3, even if the approach had been robust, there is no reason that these benefits should be excluded from the status quo.

B.2.4 Benefits from the replacement of the RCPD charge with a physical charge based on capacity

The CBA estimates that the replacement of the RCPD charge with a charge based on physical capacity will result in total benefits of \$90 million over the 20-year modelling horizon. The benefits of removing the RCPD charge come in three forms:

- avoiding inefficient investment in new distributed generation (DG);
- avoiding inefficient operation of existing DG; and
- avoiding inefficient implementation of new demand-response programs.

OGW has compared:

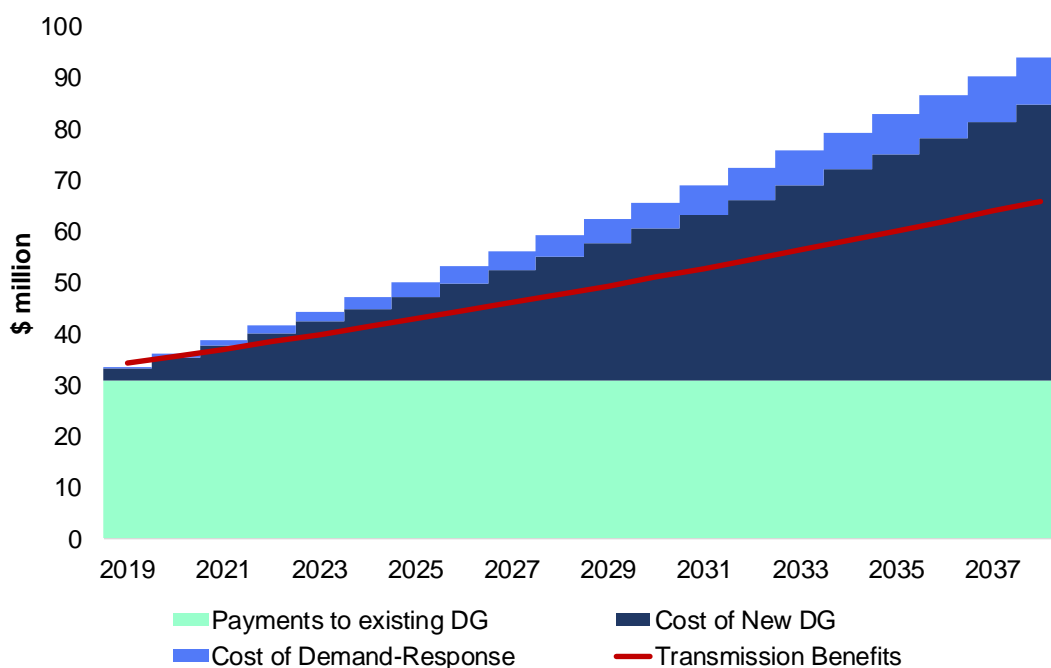
- a projection of total expenditure on new DG, existing DG, and new demand-response programs under an assumption that the RCPD remains in place; and
- an estimate of the avoided transmission costs arising from these services, i.e., the total capacity of new DG, existing DG, and new demand-response multiplied by an estimate of LRMC of transmission services.

Figure B.8 illustrates this comparison. By way of explanation, the green, blue and purple bars represent OGW's projections of expenditure on DG and demand response. The red line shows the estimated avoided costs of transmission associated with these services.

⁹⁵ OGW CBA, p.49.



Figure B.8: Costs of DG/demand response versus transmission benefits



The difference between the total costs of DG and demand response less the transmission benefits that they provide – i.e., the portion of expenditure above the red line – represents the net loss, or inefficiency, from retaining the RCPD. OGW’s estimate of benefits from removal of the RCPD is given by the present value of these cash flows.

The basis for projections of DG and demand response capacity is unclear

We note that a critical driver of the results is the estimate of future investment in DG and demand response under the RCPD charge. The CBA assumes that:

- the quantum of DG will rise linearly over a period of 20 years to reach a level equal to 5 per cent of total forecast customer load; and
- the quantum of demand response will rise linearly over a period of 20 years to reach a level equal to 5 per cent of total forecast customer load.

In its report, OGW states that:⁹⁶

‘We have assumed that new distributed generators ... can only contribute new capacity up to 5% of system peak demand in any year, but that it will take 20 years to reach that level.’

A similar statement is made in relation to new demand response capacity:⁹⁷

‘We have assumed ... that this would be capped at 5% of overall demand in any year for the same reasons as outlined above for distributed generation, and that it will take 20 years to reach that level.’

⁹⁶ OGW CBA, p.44.

⁹⁷ OGW CBA, p.45.



It is unclear why OGW has assumed that investment in DG and demand response will inevitably rise to such high penetrations over the next 20 years. In our opinion, this assumption has no basis and is unlikely to be reasonable.

A further striking assumption is that much of that new DG is forecast to be embedded diesel plant. Currently, there is around 12 MW of embedded diesel generation in New Zealand. The CBA assumes that this would increase by more than 4000% to 500 MW if the RCPD charge is retained, as customers seek to avoid RCPD charges.

This assumption is based on an unsubstantiated assertion that all other forms of cheaper distributed generation have been exhausted, leaving the most expensive option: diesel. No further evidence or analysis is provided to support this assumption. In our opinion, it is not credible. Although there could well be *some* additional diesel generation, a 40-fold increase is not a reasonable projection.⁹⁸

Against this backdrop, it is relevant to note that when Transpower was deciding whether to weaken the RCPD to its current level in the LNI and LSI, it estimated that this would render the existing 12MW of diesel generation uneconomic.⁹⁹

There is also a large error in the calculation of the profitability of those hypothetical diesel plants. Although OGW notes that distributed generators would need to operate for at least 200 periods in order to 'hit' the 100 peaks, this is inadvertently overlooked when calculating the profitability of those units. Specifically, the calculation neglects to consider that there would be many periods where the plants would be running and incurring costs, but *not* during a peak period when they would receive 'avoided cost of transmission' payments.

B.2.5 Benefits from introducing a more comprehensive PDP

The CBA estimates that there are \$10.3 million in benefits available from introducing a more comprehensive PDP charge. OGW states that these benefits arise when:¹⁰⁰

'... the PDP is explicitly ensuring that a facility will continue to operate due to the now positive gross profits that it would not have been achieving had the more comprehensive PDP not been in place.'

Table B.4 summarises OGW's calculation of the annual benefits stemming from introducing the proposed changes to the PDP. As far as we can gather, the analysis is confined to a single customer, i.e., Pacific Aluminium.

⁹⁸ To be clear, that is not to say that there would not be benefits from addressing any incentive problems arising under the current RCPD charge. It is simply to say that the CBA appears to have inflated the size of those benefits by assuming unreasonably that there would be a flood of the most expensive form of distributed generation.

⁹⁹ Transpower's CBA is available [here](#).

¹⁰⁰ OGW CBA, p.48.



Table B.4: CBA calculation of annual benefits from introducing a more comprehensive PDP

			Current PDP		Post-PDP Changes			
Aluminium price (USD per tonne)	Probability	Change in aluminium price vs base case	Change in revenue (\$ million)	Change in profit (\$ million)	Change in revenue (\$ million)	Change in profit (\$ million)	Value adjusting for probability (\$ million)	Benefits (\$ million)
1400	10%	-25%	(\$224.0)	(\$139.7)	(\$186.3)	(\$102.0)	(\$10.2)	\$0
1450	10%	-22%	(\$200.1)	(\$115.7)	(\$162.3)	(\$78.0)	(\$7.8)	\$0
1500	10%	-20%	(\$176.1)	(\$91.8)	(\$138.3)	(\$54.0)	(\$5.4)	\$0
1550	10%	-17%	(\$152.1)	(\$67.8)	(\$114.3)	(\$30.0)	(\$3.0)	\$0
1600	10%	-14%	(\$128.1)	(\$43.8)	(\$90.4)	(\$6.1)	(\$0.6)	\$0
1650	10%	-12%	(\$104.1)	(\$19.8)	(\$66.4)	\$17.9	\$1.8	\$1.8
1700	10%	-9%	(\$80.1)	\$4.2	(\$42.4)	\$41.9	\$4.2	\$0
1750	10%	-6%	(\$56.1)	\$28.2	(\$18.4)	\$65.9	\$6.6	\$0
1800	10%	-4%	(\$32.1)	\$52.2	\$5.6	\$89.9	\$9.0	\$0
1850	10%	-1%	(\$8.2)	\$76.1	\$29.6	\$113.9	\$11.4	\$0



The steps of the calculation are as follows:

- **Columns 1 and 2** – the CBA assumes that there are 10 possible outcomes for aluminium prices, each with a probability of 10 per cent.
- **Columns 3 and 4** – each outcome for the aluminium price has an associated percentage change in revenue for Pacific Aluminium, versus its 2014 revenue of \$895.7 million.
- **Column 5** – assuming that any reduction in revenue translates into a direct fall in profits, each outcome is associated with a change in profit.
- **Column 6 and 7** – after the proposed changes to the PDP, revenue and profit are calculated to increase in line with the reduction in transmission charges for Pacific Aluminium (i.e., \$37.7 million).
- **Column 8** – OGW multiplies estimated profits after changes to the PDP by the probability of each outcome (i.e., 10 per cent).
- **Column 9** – benefits occur for those outcomes for which there are positive profits after the changes to the PDP, but for which there were negative profits under the current PDP.

This approach yields annual benefits of \$1.8 million – a value which OGW estimates will persist for eight years, with total benefits of \$10.3 million in net present value terms.

We have described in section 7.3.3, that there is no reason that these benefits should be excluded from the status quo case. For example, if we were to add a ‘government subsidy’ of \$37.7 million to the profit column for the Current PDP, the approach would yield no benefits.

B.3 Estimation of costs

OGW has considered the following two broad categories of costs:

- **Incremental costs**, i.e., costs incurred by the industry under the different options compared to the status quo. These include upfront and ongoing costs of implementing each option, and are assumed to be incurred by both Transpower and the EA.
- **Avoided incremental costs**, i.e., costs that will be avoided as a result of the implementation of each option under the status quo. This section has focused on estimating the costs related to disputes that will be avoided by ‘adopting a new approach that is well documented and understood’. Avoided incremental costs are in effect a benefit.¹⁰¹

Table B.5 shows a breakdown of OGW’s estimated costs for each option. The result is that OGW has in fact estimated that there are additional benefits arising in the form of avoided costs.

¹⁰¹ OGW CBA, p.59.



Table B.5: OGW estimated costs for each option (\$ NPV terms)

Scenario	Option 1	Option 2
Incremental costs	2,631,912	3,472,473
Avoided incremental costs (ie, a benefit)	(3,036,974)	(5,512,914)
Net Costs	(405,062)	(2,040,441)

B.4 Comparison of costs and benefits

Having estimated costs and benefits, the final result of the CBA is simply the total benefits less the costs (noting that the CBA estimates that costs are in fact negative, i.e., yield a further benefit). There are two assumptions that are relevant to the overall comparison of costs and benefits:

- **Discount rate** - the CBA assumes a pre-tax real discount rate of 8 per cent.
- **Evaluation period/time horizon** – the CBA assumes a 20-year evaluation period.

We note that the evaluation period for the CBA is not consistent across the entire CBA, i.e., the benefits from removing the SIMI charge have been assessed over a 30-year timeframe. The stated rationale for this is that:¹⁰²

‘...the 20-year timeframe was unduly influenced by specific timing related issues that affected when generation assets were expected to be developed in the model, which skewed the results when undertaken over this shorter evaluation period.’

This statement suggests that OGW has been unable to deal appropriately with ‘end-effects’ in its modelling, i.e., the problem of large, lumpy cash flows at the end of the modelling horizon having a substantial influence on the results. There are well-established approaches to dealing with end-effects in this type of model. However, extending the modelling period for a single series of benefits is not among them. A more appropriate approach would be to assess the residual value of *all cash flows/assets* at the end of the modelling period.

¹⁰² OGW CBA, p.55.



Appendix C Previous reports

Throughout this report we have drawn extensively upon materials contained in earlier papers by Axiom economists; namely:

- Green *et al*, *Transmission Pricing Methodology – Economic Critique*, February 2013;
- Green *et al*, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Transmission Pricing Conference – Response to Questions*, 25 June 2013;
- Green *et al*, *Economic Review of EA CBA Working Paper, A Report for Transpower*, October 2013;
- Green *et al*, *Letter to Mr Carl Hansen, Chief Executive, Electricity Authority, Sunk Costs Working Paper*, 12 November 2013;
- Green *et al*, *Avoided Cost of Transmission Payments, A Report for Vector*, January 2014;
- Green *et al*, *Economic Review of EA Beneficiaries-Pay Options Working Paper, A Report for Transpower*, March 2014;
- Green *et al*, *Economic Review of TPM Options Working Paper, A Report for Transpower*, August 2015;
- Green *et al*, *Potential Generator Market Power in the NEM, A Report for the AEMC*, 22 June 2011; and
- Green *et al*, *New Zealand Transmission Pricing Project, A Report for the New Zealand Electricity Industry Steering Group*, 28 August 2009.

Where a matter has been explored in one or more of these documents, we have not sought to repeat all of that material in this report – even when it remains equally germane. Rather, in the interests of parsimony, we have provided a summary of the key points and supplied appropriate references to this earlier work.