Transmission pricing options

Advice regarding EA working paper on grid charging

NZIER report to MEUG

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Final

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Key points

1. The Electricity Authority (Authority) has released a working paper on charging options for the TPM that offers multiple options for allocating Transpower regulated revenues to grid users.

2. The Authority currently sees several problems with the existing TPM as being;
   - Not adaptive - unused capacity exists in the grid
   - Not cost reflective across the grid
   - Users need to be more engaged with investment processes
   - Not durable – free riding and cross subsidies exist in the grid.
3. The options proposed by the Authority include a complex mixture of layered decisions about:
   - what costs should be re-allocated – costs of the existing assets or only expected costs from new assets
   - how costs should be re-allocated
   - transition arrangements for implementation

   The Authority has provided indicative modelling for each of the options that indicates future variation in the application of the proposed cost allocators.

4. The primary focus of the Authority charging options is to reallocate costs to better match grid users access to the *capacity* offered by the grid at particular locations. However we suggest that the Authority's rationale for using different proxies to estimate capacity for direct connects and EDBs needs to be clarified and that the EA needs to prescribe the method for estimating capacity in its guidelines.

5. Through such a refinement process we urge the Authority to identify and prescribe the appropriate allocators within the TPM guidelines so that the implementation can be streamlined and that the outcomes for grid users will align with the Authority's final TPM proposals.

6. We see the AoB charge as static rather than dynamic. The combination of the long review period for the deeper connection charges and the static nature of the AoB allocation suggest that once they are established both of these charges are unlikely to be responsive to shorter term changes in grid costs or use of the grid. This is a material weakness of the proposed options.

7. We have concerns with the 'black box' nature of the deeper connection mechanism. It appears to be based on the judgements of its architects rather than representing the potential for asset users to club together and contract for these assets. Despite saying this we view flow tracing as providing an objective test of what portion of grid costs the industrial direct connects and generators were paying for compared to that parts of the grid they were using.

Putting aside which allocator to use, for us this provides initial evidence that the Application A proposal offers a more efficient allocation of costs than does the status quo.

8. In respect of encouraging greater scrutiny by EDBs of Transpower investment, for us the benefits of the proposed Application A are less clear. The EDBs as a group are currently paying the bulk of the grid costs which also comprise a significant part of their own cost structure. We therefore think that the EDBs already have a strong incentive to encourage both Transpower to match investment to demand and their customers to use distribution assets and the grid more efficiently. If the existing incentive is not driving the level of engagement expected by the Authority then the question becomes how is Application A expected to change the behaviour of affected EDBs. This question should be a key focus for the CBA.

9. The Authority TPM re-allocation mechanisms imply a wide variation in the definition of the 'inefficiency' of the current TPM cost allocation. Application A re-allocates a net annual $100m of all existing grid asset costs from direct connect industrials and generators to EDBs. For us this defines the TPM problem with the TPM as 'inefficient and not cost reflective allocation of existing costs'. Application B re-allocates a very small amount of new asset costs only and limits the definition of the problem to 'the recovery of the cost of future grid investments from the expected beneficiaries of those investments'.

10. Conceptually, the mechanisms to reallocate grid costs proposed by the Authority under Application A appear to have the potential to improve the clarity of signals to grid users about the costs of access to the grid and therefore to improve the efficiency of gird use and possibly investment decisions. The caveat on this statement is that the proposed changes still require current grid users to pay for unused capacity.

11. Overall the Authority is on the right track. We prefer to see more use of mechanisms that can identify real rather than deemed beneficiaries such as SPD, but we recognise the difficulties that come with trying to achieve this.

12. We urge the Authority to press on with developing an issues paper that prescribes the cost allocation mechanisms and provides a suitably quantified cost benefit analysis.

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1. Introduction

As a part of their ongoing review of guidelines for Transpower transmission pricing methodology (TPM) the Electricity Authority (Authority) has released a working paper on charging options for the TPM – that offer a complex set of choices between new allocation mechanisms as well as the scope and timing of the application of these mechanisms. The key decisions are:

- Replace the HVDC/RCPD charging with a:
  - new set of cost allocation options 'deeper connection', 'area of benefit' and 'residual' (along with potentially elements of long run marginal cost and SPD benefit estimates)
  - new basis for allocation; AMD for direct industrials, $/MWh for generators and Authority deemed capacity for EDBs
- Reallocate all existing costs (Application A) or just the cost of new assets (Application B)
- If Application A is chosen, consider four transition options:
  - two of the options propose an adjustment period for the costs re-allocated to EDBs as a group, before being finally allocated to individual EDBs in line with Application A.
  - the other two options phase in the changes by either capping the rate of increase or spreading the increase over 5 years.

The Authority seeks submissions on these options, the application of the charging options to part or all of Transpower regulated asset base and whether it is desirable to have implementation subjected to some form of transition arrangement.

The working paper provides some insights to the possible financial impacts of the charging options based on modelling and simulation work undertaken by the Authority and its advisors. The Authority is also prepared to consider variations to the charging mechanisms within the proposed charging options as possible if the mechanisms proposed in the paper can be improved upon.

The financial trickle-down analysis in the paper describes the financial impacts on grid connected users (generators, industrial users and distribution network businesses, EDB's) but does not extend to how the charges would be passed through from the EDB's to consumers connected to those distribution networks.[1]

1.1.1. The TPM review process

As mentioned there has been an ongoing review of the TPM for the last several years. A major milestone was the issues paper that the Authority published in 2012 which proposed that beneficiaries of the grid be identified and charged for grid use

[1] The financial trickle-down in the paper indicates that about 85% of Transpower revenue will be indirectly allocated (via the EDB's to consumers that are connected to the EDB's.

using a near real time approach based on the vSPD market settlement system.[2] There have been a number of developments with and around the TPM since then.

- Following the 2012 issues paper the Authority TPM review path to 2015 has included publishing several working papers that considered matters raised during and after the 2012 consultation process. One of those papers was a reconsideration of the problems with the current TPM, published in 2014.
- Transpower have recently proposed several 'operational' changes to existing TPM – described as short term fixes to some of the problems identified in 2014, while the Authority TPM review goes on. These are short term fixes to the perceived' problems' with the RCPD and HVDC.[3]
- Transpower has just entered their second regulatory control period (RCP2) which has approved regulated revenues rising to be more than $1b over the next 5 years.
- The Commerce Commission has started the first formal review of the Input Methodologies (IM's) that are used to set regulated revenues and prices for regulated networks including Transpower. There is potential in this process for changes to how Transpower revenues are set which will flow through to transmission pricing of course.

We mention again here the point that we made in 2012 – the Authority is trying to fix 3 tough economic problems related to grid usage and investment with a pricing mechanism but in addition we note and agree that there are better ways to allocate sunk grid costs than current TPM.

1.1.2. The perceived problems

In summary, the Authority currently sees several problems with the existing TPM as being;

- Not adaptive - unused capacity exists in the grid but the TPM encourages RCPD charge avoidance
- Not cost reflective across the grid and to specific users and groups of users
- Users are not engaged with investment processes
- Unfair and not durable – free riding and cross subsidies exist in the grid.

The Authority is proposing to use a multi layered charging structure to change user behaviour and limit avoidance of grid charges. Specifically the charging mechanisms that the Authority is proposing to use to resolve these problems are to;

- retain existing connection charges – seen as representing 'voluntary' contracts and are therefore market like.
- completely restructure the existing interconnect (I/C) and HVDC charges as the status quo is deemed as not fit for purpose – in short there is a better way to charge for the grid. They propose deeper connection charges for

[2] For us this was a big step forward in approaches to allocating grid costs but it suffered from difficulties with defining parameters in the calculations and with application to grid users, that together resulted in a large residual having to be allocated in a 'not beneficiary' manner.

[3] RCPD is the current method of charging demand (consumers) for their share of the coincident peak demands in the transmission grid while the HVDC link is charged directly to South Island generators. Transpower suggests that there are more efficient charging options for both these methodologies.

certain assets in particular locations, but not all assets, and to allocate costs of particular large investments to those parties who were deemed to be beneficiaries at the time the grid investments were approved. A substantial residual cost pool remains.

- charging options are new and in some ways novel but the Authority has moved away from the 2012 SPD based approach (to a more static than dynamic approach) – trying to mimic market like results with deemed-voluntary contracts.
- overcome SPD 'under the hood' structural flaws with new options that identify benefits from individual assets and widen the beneficiary net to be much more regionally based (deeper connection and Area of Benefit charges).
- use very concentrated locational signals to make load/generation 'care' about grid investments

What then do the options mean? We believe that the Authority is trying to give as many grid assets as it can a 'locational' dimension and thereby identify possible beneficiaries and eliminate free riding – the focus is on location of users in relation to assets and asset capacity. This is the Authority approach to 'cost reflective' charging, however because of the absence of 'identified' beneficiaries, our initial view is that the proposed options appear to be more administrative solutions.

Our approach to this assessment is to consider;

- rock back and ask 'what matters here' – what is important to consider in this review and assessment.
- the overall objectives for allocation grid costs – how do the Authority options fit with overall objectives for grid charges?
- the ability of the options to identify beneficiaries– this is the fundamental issue to resolve because even in the absence of new investments those who benefits from the grid will change over time which needs to be monitored.
- who is impacted and the redistribution of charges – the trickle down to grid customers and to consumers behind the GXP needs to be assessed in detail.
- outcomes, both intended and unintended. This assessment flows from the trickle down analysis and will be influenced by participants perceptions of the TPM changes
- potential for cross subsidy remaining because TPM charges and benefits are not necessarily in sync.
- complexity and transparency of what is proposed– if these changes to the TPM do not have the desired effects because they are hard to understand and implement or they are not responsive/dynamic then the whole process could well be a waste of time.

Then pull together a fitness for purpose assessment and provide feedback to the Authority on where we see the need to focus in the proposed 2016 Issues paper and benefits appraisal that flows from their use of any of these charging options.

2. Transmission pricing objectives

The need for a regulated 'transmission pricing methodology' arises because of the natural monopoly nature of the transmission grid which drives large economies of scale in grid augmentation such that first best marginal cost pricing will not recover the total costs of the grid. Therefore there needs to be a second best pricing approach that raises the required revenue but minimises distortions to both the efficient use of the grid and the investment decisions of grid users. The question here is what matters when thinking about the TPM – what do efficient prices look like in a second best situation.

2.1.1. What does current literature suggest?

There is reasonable agreement in the literature regarding what matters when developing transmission pricing arrangements. For instance - in an early 1997 publication Green suggests six principles that should be considered:

- Promote efficient day to day operation of bulk power markets
- Signal locational advantages for investment in generation and demand
- Signal the need for investment in the transmission system
- Compensate the owners of existing transmission assets
- Be simple and transparent
- Be politically implementable[4]

More recently Brunekreeft et al suggest that transmission charges should encourage:

- Efficient short run use of the grid
- Efficient investment in expanding the grid
- Efficient signals to guide investment decisions by generation and load
- Fairness and political feasibility
- Cost recovery [5]

Even more recently Hogan takes a different, simpler view and argues that parties should be charged for the grid on the basis of their benefits. He maintains that this will avoid the difficult task of 'inventing' charging mechanisms that discriminate between regions, types of consumer and the different users of the grid. In his 2011 paper[6] he promotes overall efficiency driven by the notion that cost allocation should be on the best approximation *of all types of benefits* (reliability, economic and public policy related benefits). Investment efficiency is achieved by using a regulatory body to approve lumpy periodic investments and then allocate costs according to the

[4] Green R. (1997). Electricity transmission pricing, an international comparison.

[5] Brunekreeft, Neuhoff and Newbery. (2005). Electricity transmission, An overview of the current debate.

[6] Hogan W. (2011). Transmission benefits and cost allocation.

distribution of benefits. The focus is however on the efficiency of the electricity system overall. We agree with this thinking.

Besides investment and operating efficiency, Hogan introduces the notion that the principle of beneficiary pays needs dimensions of 'fairness' because the government regulators mandate the scope of both transmission investment and cost recovery and then they 'compel participation' on the basis of benefits arising. Importantly he also points out that absent a beneficiary pays principle it is very difficult to maintain a mixed system of voluntary connection with investments mandated and centrally planned reliability investments. It is also very difficult to efficiently incentivise generation and load when they in part compete with and are complementary to the grid.

Durable changes to the TPM therefore have regulatory, political and commercial dimensions.

2.1.2. Trade-offs need to be made

To deliver on these objectives in a practical sense we suggest that the TPM needs to:

- Consider the level and efficiency of the regulated revenue cap
- Mimic the outcomes from a competitive market and be subsidy free
- Include mechanisms that provide adequate locational signals
- Be implemented to reflect grid costs and grid utilisation

This is not a straight forward process. For us various aspects of efficiency are important to the pricing process and importantly, trade-offs need to be made to prioritise amongst these TPM objectives and principles. Efficient day to day operation and use of the grid can be inconsistent with longer term investments by the grid owner, as well as by generation and demand. This can be mostly attributed to the disconnection between the operation of the wholesale nodal market and the centralisation of grid planning & control of information on the grid. It seems to us that the Authority is trying to use the TPM options to bridge this gap.

2.1.3. Grid efficiency

In doing so the Authority applies its economic framework for decision making to the evaluation of the pricing options in the discussion paper with 'market or market like' approaches seen as being more efficient and preferred over more administrative cost allocations. While the economic framework is based on sound principles it seems to us that the Authority have not provided justification for mechanisms to be classed as market based when they initially appear more administrative.

Productive efficiency within and of the grid suggests to us that use of the grid should be maximised (energy volumes and/or grid load) with respect to the capacity of the network – that is, grid utilisation is most important subject to potential impacts on other types of efficiency.

Allocative efficiency across not just the transmission grid but the wider electricity system, including consumers, is concerned with allocating production resources to their highest value uses. Here producers and consumers should be able to make

decisions about how they obtain and use the electricity they need, taking account of the relative prices and productive efficiency of the resources they elect to use.

Dynamic efficiency is most important for long lived assets such as the transmission grid because it results in the efficient allocation of resources over time – that is generators and consumers make optimal investment and consumption decisions over an extended period of time.

In amongst both these dimensions of efficiency and the objectives for grid pricing there are inherent tensions – nodal pricing for instance facilitates market based trade between participants (generation and consumers allocating resources to their best use based on pricing signals and future expectations) while grid central planning and cost recovery are regulatory interventions that try to mimic a non-existent market outcome.[7]

Developing a mechanism for regulated grid pricing to optimise these objectives and adapt to deregulated market demands over time is a very difficult task - this is Hogan's point we note above.

[7] The tension within Part 4 objectives between long term benefit for consumers and certainty for producers sits uncomfortably in this mix too.

3. The economic arguments

The transmission grid exhibits economic characteristics that further complicate efficiency objectives, making evaluation of the Authority options against accepted pricing objectives tricky.

3.1. Indirect and complex

Transmission pricing is an exercise with indirect effects – direct effects are limited because there is no market for grid services, the grid has huge economies of scale and it exhibits meshed flow characteristics. Because of this both the physics and the economic characteristics of transmission grids (and distribution networks for that matter) limit the extent to which accepted pricing principles can be practically implemented. Short run economic costs are orders of magnitude lower than the mostly fixed long run costs while causality of both cost types is difficult to determine because of network externalities.

Externalities from physical loop flows exist within electricity networks such that there are multiple paths between generation and load and that change to load or to grid infrastructure at a particular location will affect electricity flows and therefore usage patterns across other parts of the network. This 'path of least resistance' characteristic of electricity flows suggests that new investments in both reliability and economic grid assets will have an impact on network usage far beyond their immediate geographic location. This reality limits the scope of direct attribution of network costs (and equally the identification of direct beneficiaries) and leaves the architects of the pricing structure with the difficult and complex problem of indirect allocation of the sunk costs.

Beyond externalities, grid costs exhibit traditional economies of scale. Transmission grid investments are usually large and lumpy – taking time to construct, which results in average costs that change materially over large capacity increments. These scale economies also result in chunks of unused 'excess' capacity that exist for periods of time between the lumpy investment increments (or because demand turns out to be different from forecast). This situation in turn complicates the longer term planning of the grid, making optimal/cost minimisation planning decisions complex and heavily reliant on detailed information on network configuration and costs. This information need almost always results in grid planning work being centralised as a function of the transmission grid owner.

Information asymmetries result from this situation and compromise the role of outsiders (including the regulator to a certain extent) when scrutiny of the grid owners proposed investment plans are called for and when the direct causal connection between the investment and grid connected parties is very difficult to identify.

3.2. How to price the transmission grid?

That being the case, from an economic perspective the question for us at this stage is what we want the TPM to achieve. In our view we believe objectives for the TPM could be:

- efficiency – with elements of being least cost, cost reflective and dynamic over time.[8]
- recover fixed costs – but lack of incentives on Transpower from mandated cost recovery is problematic
- transparent – to enable monitoring of the effects of charges on grid users and to identify whether charges are really market like or administrative in disguise.
- Non-discriminatory – subsidy free and competitively neutral

These 'pricing' objectives are however difficult to relate to the transmission grid in a practical manner and as discussed involve trade-offs regarding their relative importance that will change as grid and grid users circumstances alter over time.

If we start with the proposition that the efficiency objectives of the grid are optimised from the existence of (marginal cost based) nodal pricing we then turn to the practicalities of applying these objectives to grid charges to:

1. recover investment costs – which suggests that overall charges should be equal to average costs
2. provide incentives for investment – suggests that charges should be de-averaged by location and based on long run marginal costs

We see an obvious tension between these two approaches to transmission pricing that the Authority TPM mechanisms need to overcome in a practical sense.

3.2.1. Cost recovery

Regarding the cost recovery priority, for us the key question here is: If grid efficiency directs the approach to cost recovery as the Authority contend, should efficient use of the grid be influenced by locational signals over and above the efficient signals that the nodal energy market provides. The Authority certainly believes that it should – deeper connection and AoB charges are locational charges that are proposed to identify 'deemed beneficiaries'.[9]

Locational vs non-locational % split within the TPM options is therefore a big factor in the scheme of the TPM. This is because a locational component that is too high will over-signal the importance of location and have the potential to adversely influence demand-side operating decisions compared to demand behaviour from exposure to nodal pricing alone. This has the potential to deliver a less efficient outcome.[10]

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8 A second question follows from here: is efficiency a regulatory issue and can pricing alone be used to deliver an efficient outcome? – we think not entirely.

9 We like the notion of locational signals but have reservations about whether the Authority have adequately justified classifying these users as beneficiaries.

10 In Australia this split is limited to 50:50 to approximate LRMC vs average cost. While the most efficient outcome will (in theory) come from response to the locational signals from nodal pricing, this is not to say that there are more efficient ways to recover sunk investment costs than

Charging mechanisms. The trick therefore is to identify the cost recovery mechanism(s) that will limit potential adverse impacts while still meeting the pricing objectives of cost recovery. This in turn suggests to us that analysis of the Authority charging options needs to pay particular attention to the impacts on demand side operating behaviour. We see this is a particularly important component in the cost-benefit analysis in the next stage of the TPM review process.

There is another complication. In the presence of network scale and scope economies, grid charges should be set between the incremental and standalone costs thereby mimicking the conditions that would be found in a contestable market.[11] For the transmission grid the range between these cost bounds is large.

On top of this, the identification of the 'optimal charge' is further confounded by the presence of loop flows across many grid assets which affect grid costs and usage. The charging mechanisms therefore need to be able to reflect several dimensions of grid economics as well as be implementable and able to be understood.

Three commonly used examples of generic grid charging mechanisms for recovering costs are:

- Flat tax 'postage stamp' charging on load or energy used basis. This approach has the attraction of simplicity and promotes an efficient system operator but it does little to incentivise load or generation efficiencies. It is not especially cost reflective nor does it identify possible beneficiaries. NZ & Japan do this.
- Using nodal pricing data to allocate charges to grid users - in the manner of the Authority 2012 SPD proposal. This approach is seen as better than postage stamp charges but as mentioned earlier it has other problems depending on the nature of the mechanism and how it is implemented. PJM do this.
- Zonal pricing where grid nodes are aggregated into locations of larger size. Again this approach is not seen as being particularly cost reflective because of averaging across locations and users, while the zones are often arbitrarily defined. Australia & California do this.

Within these generic mechanisms there are a range of implementation methods which involve various judgements and trade-offs between the objectives that we describe earlier. Our understanding of the advantages and disadvantages of potential cost recovery charging mechanisms are as follows.

Table 1 Charging mechanisms

Mechanism	Advantages	Disadvantages
Flat rate 'postage	Meets equity considerations (seen as	Violates the recover fixed costs with fixed

the current TPM. The use of nodal pricing data to identify probable beneficiaries of grid assets such as the SPD approach the Authority proposed in 2012 was for us a game changer in this regard, even though it had under the hood problems.

11 The Authority describe the cost floor as Transpower,s 'variable' costs of around $250m and contend that all grid connected parties should be charged for these costs regardless of their use of the grid, however we have questions regarding the conditions under which these costs would vary. Our summary and analysis of Transpower regulated costs (revenue) is in section ?XX? of this report.

stamp' charges	being 'fair' because it is based on usage).	charges to limit distortions rule.
	Similar types of customers pay similar charges	Like a tax, postage stamp charges reduce consumption
	Maintains relativity of costs and hence can limit distortion in nodal markets	End consumers see a small variable charge which attracts little or none of their attention.
	Less distortionary than peak charges when grid has excess capacity	Not reflective of users cost characteristics
		Provide poor incentives regarding location with users investment decisions. Ignores distance.
		Likely more distortionary than alternatives
Location based charge	Reflect costs in a particular location	Existing location decisions are sunk and cannot be undone so careful design is needed to avoid distortions.
	Deeper network costs can encourage 'correct' location decisions if they reflect actual LRMC	'Averaged' location charges likely to distort signals
		Spare capacity inflates true LRMC and distorts locational signal.
		Attribution difficulties mean signals are diluted and indicative only
		Needs to be dynamic to reflect changes in value/costs of demand and grid investment
		New load/generation results in re-balancing of charges - unstable
		Large informational/forecasting and managerial issues
		Potentially quite distortionary from reduced trade, lack of transparency and from unfair simulation of costs and usage.
Peak Usage charge	Reflect grid provisioning for peak loads	Discourage grid usage when there is spare capacity
	Dynamic over time	Can penalise some generators through RCPI
	Can be averaged over few or all charging periods	Ignores distance and location costs
		Peak demand is driven by various factors including nodal prices – therefore base charges on spot prices
		Likely more distortionary than alternatives

Source: NZIER

Much of our assessment of the Authority TPM options in this report is focussed on the judgements and trade-offs that the Authority appear to have made in developing these options as well as on how their chosen mechanisms are likely to work and

therefore be able to (or not) deliver on the objectives that we discussed earlier. That is - can the cost recovery mechanisms achieve the intended outcomes.

3.2.2. Investment incentives

Using transmission pricing as a tool to encourage participants involvement in efficient investment decision making is a different kettle of fish.

The overall objective of network efficiency also embraces the need for efficient investment over time – dynamic efficiency improvements, not only for grid investments but also for generation so that the overall cost of providing electricity to consumers is minimised. Clearly transmission pricing also impacts the timing, location and nature of demand side investment decisions. Overall this is a very difficult coordination task and one that usually requires much more than simple (or complex) transmission pricing methodologies to resolve.

The nature and efficiency of the nodal energy market has a direct influence on investment choices such that (generation or load) investors will 'present value' their views of future nodal prices into their decisions regarding the location, timing and type of investments. This side of the investment coin is largely steered by market forces.

The other side of the coin is investment in the grid itself. The information from the nodal market makes its way into grid investment decisions via the traditional approach to grid development/coordination. Here planners take an informed long term view on generation and load investments and craft a plan for the grid.[12] This process results in a central repository of information (to understand/scrutinise grid investments)which is with the planners who work inside the transmission owner organisation and is likely not, or only partially, accessible to other parties including the regulators.

Given that these conditions make it difficult for parties outside of the transmission owner to access sufficient information to scrutinise grid investments, for us the question for the Authority charging options is whether transmission pricing is the appropriate tool to incentivise involvement in grid planning and encourage efficient investments. That is, are the difficulties with transmission coordination and investment a pure pricing issue or an issue with regulatory governance?

The Authority is of the view that investment efficiency can be improved with appropriately structured transmission pricing. The options they propose have a strong locational bias which they believe will encourage parties located in a particular region to take a keen interest in investment proposals that will affect their region.

We have reservations regarding the ability of transmission pricing to make up for market failure (natural monopoly from huge grid scale and scope economies), for potential regulatory failure due to information asymmetries and for inefficiencies that result from a grid development and coordination task that is difficult to do in the presence of much uncertainty.

We are also of the view that there are probably imperfections in the network planning system that result in network 'over-build' which distorts locational signals

[12] Clearly they take in a wide data set including likely price paths at the nodes where investment is expected.

and hence the efficiency of transmission investments. In these cases the locational mechanisms in the grid pricing options could be used to reinforce the weakened signals, subject to the reservations that we have due to the impacts of loop flows across regions.

But there are other experts (Biggar for instance[13]) who argue that, in order to restore efficient network investment signals distorted by over-build, parties at both the same node and different nodes may need to face different transmission charges. This argument/logic causes us to further question the ability of uniform locational charges (concentrated across an area – say AoB or deeper connections zones) to compensate for distorted locational signals and encourage efficient investments.

In summary we have a number of material concerns about whether these options will have the intended impact on investment decisions compared to the status quo.

3.3. NZIER evaluation

The Authority has clearly made its own trade-offs regarding the competing priorities with grid pricing objectives – efficient investment and use of the grid matters most.

Our take on the notable trade-offs is that the Authority:

- has adopted a more pragmatic 'principle driven' approach to defining the problems with the current TPM
- rate location of grid users and assets as a high priority
- places a heavy emphasis on utilisation of the grid – productive efficiency
- has decided that deemed beneficiaries (ex post via the deeper connection charge and ex ante via the AoB charge) is adequate in the absence of identifying actual beneficiaries
- believes that average usage of assets provides an adequate economic signal that is 'cost reflective'
- gives a lower priority to Hogan's important concerns regarding fairness, market-central planning tensions and the efficiency of the required revenue pool.

Overall, the Authority argues that charges need to be cost reflective and eliminate cross subsidies. Willingness to pay is somewhat set aside, as is the Hogan argument that it is too difficult to apply charges that represent contracts, quasi contracts and mandated cost recovery to grid users who may not see themselves as beneficiaries of grid assets. Despite saying this we see the Authority focus on efficient grid usage and investment as the right one. We do not necessarily agree with all the details of their perceived problems but we do agree that there is a better way to recover Transpower costs than the status quo.

So, the detail within the mechanisms are most important if the Authority is to achieve the objectives in the least distortionary (most efficient) manner.

In the tables below we assess the mechanisms that have the more material impacts on the allocation of Transpower regulated revenues (deeper connection, AoB and

13 Biggar (2009). framework for analysing transmission policies in the light of climate change policies

residual) against our economic objectives and consider the ability of the whole Base Case option to be effective at incentivising efficient decisions.

Table 2 Deeper connection – economic evaluation

Criteria	Does it encourage efficient use of grid
Least cost grid services	Not especially efficient – embeds excess capacity in charges and averages node and zonal charges which is less efficient.
Cost reflective	Averages asset usage costs - doesn't reflect costs caused by different users.
Market like – transparent	Partly, – location based so can supplement nodal signals to the extent that these are distorted from over-build in grid. Black box approach to SPD and flow tracing likely a material negative factor.
Subsidy free	Partly, – flow trace averaging is a negative but this mechanism is better that a flat tax across the whole grid. SPD solve sets a good foundation.
Adaptive and dynamic	SPD component is a plus but is only step 1 in the process. Considerable effort will be required to monitor deeper connection in practice to enable regular updates over time as usage changes.
Identify beneficiaries?	Possibly – but most likely they will be deemed beneficiaries who may not agree they receive benefits, resulting in willingness to pay problems.
Distortionary impacts	Less distortionary if de-averaged.

Source: NZIER

Table 3 Area of Benefit – economic evaluation

Criteria	Does it encourage efficient use of grid
Least cost grid services	Unclear. Likely to be not least cost based.
Cost reflective	Yes – costs known from GIT business case.
Market like – transparent	Partly – uses GIT benefits data so could be used under a 'contracting' model.
Subsidy free	Unclear – GIT and actual costs/benefits may differ materially
Adaptive and dynamic	No – allocation of costs is ex ante GIT based for each investment and is therefore fixed.
Identify beneficiaries?	Pole 2 and 3 are among the few grid assets where beneficiaries are easy to identify and where benefits are large. Beneficiaries of other assets are deemed.
Distortionary impacts	Likely higher than lower because of the ex-ante basis of allocation and material gaps between deemed and actual beneficiaries over time.

Source: NZIER

Table 4 Residual – economic evaluation

Criteria	Does it encourage efficient use of grid

Least cost	Unclear but unlikely – depends on whether Transpower costs are efficient.
Cost reflective	No – by definition the cost pool that cannot be attributed directly to assets, users or locations.
Market like – transparent	Partly insofar as the costs are a defined, and allocated in a visible manner. Parties may be willing to contract and pay for the residual if it was seen as being necessary and efficient.
Subsidy free	No – by definition is the cost pool that cannot be identified to assets, users or locations.
Adaptive and dynamic	Possibly – depends on how adaptive and dynamic the other mechanisms are.
Identify beneficiaries?	Load (consumers) are the deemed beneficiaries.
Distortionary impacts	Likely material unless charges are carefully designed to minimise distortions (Ramsey pricing for example)

Source: NZIER

Table 5 Base case option – investment efficiency evaluation

Criteria	Does it encourage efficient investment by grid owner and users
Marginal cost signals	Limited because virtually all costs are sunk. Addition of LRMC mechanism improves investment signals going forward but seems complicated.
Cost reflective	Only partly – tiered nature of mechanisms in base case dilutes economic cost signals
Market like – transparent	Limited because mechanisms are mainly administrative arrangements which allocate regulated costs that flow from a centrally planned grid.
Subsidy free	Minimal, but only to the extent that an individual mechanism does not inhibit economic signals.
Adaptive and dynamic	Depends on the approaches used to update historical data and analysis for each charging mechanism. Addition of SPD mechanism is an improvement.
Distortionary impacts	Better than status quo TPM – locational and economic signals are improved but unclear to what extent. Embeds distortions by using data from recent past.
Will parties 'care' more about investments	Likely yes – location and magnitude of additional grid charges will get users attention, though ability to scrutinise proposals limited by central planning and information asymmetries.

Source: NZIER

For us:

- the devil is in the detail - success with these options depends on how the allocation mechanisms are designed to meet economic objectives.
- none of the mechanisms make it easy to identify whether they meet the economic criteria - the Authority has made trade-offs, some of which are hard to understand
- there is a heavy emphasis on the location of assets and grid users which suggests that the mechanisms need to be carefully designed to meet economic objectives.

- on the other hand, the sheer weight of the locational signals could just about guarantee that those parties shouldering the bulk of grid costs will 'care' about grid investments.

4. What do the options deliver?

4.1. Context - the practicalities

Here we assess the ability of the design of the individual mechanisms to deliver on the Authority efficiency objectives. The main implementation problem for the Authority is settling on a consistent and practical definition of the capacity offered by the grid. Our comments on the practical issues with the options are further expanded in section 5 of the report on implementation of the TPM options.

Our overall assessment is that the underlying principle, to allocate transmission pricing on the basis of the estimated 'optional' access to capacity, is sound. However in a practical sense there is an anomaly in the assessment of the capacity for direct connect industrials and EDB customers including industrial users.

4.2. Authority cost allocation task

The stated focus of the Authority proposals is to improve the dynamic efficiency of the TPM, measured against the existing regime which allocates:

- costs of the HVDC ($120m in 2015) to South Island generators (based on their peak injection to the HVDC link)
- remaining grid costs ($580m in 2015) on the basis of grid load's contribution to regional coincident peaks (RCPD).

The back drop to the Authority allocation task is that a number of major investments in the transmission grid have been completed and no major investment is expected in the grid in the short to medium term. The task is just about entirely a re-allocation of existing grid costs.

Importantly the options will <u>not</u> deliver a more efficient (better matched to current requirements) pool of Transpower's regulated costs. The Authority believes that it does not have the jurisdiction to discriminate between Transpower and other stakeholders in the electricity industry on the subject of under-used capacity in the transmission grid. Therefore the Authority task is narrowed to the allocation of *total approved grid costs among users as efficiently as possible*.

4.3. Options design

The current allocation method relies heavily on RCPD charges which do not discriminate on a detailed locational basis (other than the four broad geographic 'regions').

The Authority's rationale for the design of the seems to be that the RCPD based averaging has the following biases:

- over charges large users directly connected to the grid and close to the source of generation
- under charges users with either high capacity or those who have the ability to reduce their use during periods of peak load on the system

These Authority seems to argue that these biases encourage large users directly connected to the grid to reduce their reliance on the grid and blunt the enthusiasm of all grid users to critique Transpower investments.

Our assessment is that the strength of these linkages is difficult to measure. Current and expected transmission costs are one of many signals considered by all users in how and when they use energy, where they purchase that energy and in what form. While quantification of the strength of the signals is not necessary at this stage, it is essential for the cost benefit analysis. The difference in the nature and strength of signals to users under the current and proposed mechanisms along with the expected consumer response to those signals will be a key pieces of evidence in comparing the difference in outcomes for consumers.

The Authority appears to be intent on designing methodology based on allocators that are difficult for grid users to influence by altering their short term grid usage. The Authority argues that such an approach will make the methodology durable and the charging regime more certain for grid users, however we see two potential disadvantages to mechanisms designed this way. First they embed historical, inefficient, asset usage patterns into the re-allocation of costs and second the mechanisms do not consider the current excess capacity of grid assets. The approach also builds a lag into the reallocation of asset costs when either capacity or usage changes.

4.3.1. Re-allocation mechanisms

The Authority defines the allocation task as the assignment of $1,000m of Transpower's costs per year. Approximately $200m of these costs are already allocated through loss constraint excess (LCE) or user connection costs. The Authority proposes to leave the allocation of these costs unchanged.

The primary focus of the Authority is which mechanisms to use to reallocate the remaining $800m to better match the cost of the capacity offered by the grid. The cost allocation model envisions Transpower assets as resulting from a series of market like 'contracts' between grid users and Transpower. As these contracts do not exist in reality the Authority is proposing to synthesise these contracts using observed and 'optional' usage of grid assets for the existing HVDC/RCPD allocated costs.

In principle we support using access to grid capacity to allocate grid costs. However we suggest that the Authority's mechanisms (AMD for direct connect industrials and deemed capacity for EDBs) for allocating the area of benefit and residual charges needs to be refined because it directly undermines the principles of the Authority approach. It also drives the need for transition options that indirectly undermine the principled approach.

A secondary focus is which mechanisms to use to allocate the costs of future investments so that the initial users of those assets are strongly motivated to express their views on the investment and influence its timing. To assist this objective the Authority suggests a long run marginal cost (LRMC) charging mechanism in one of the options.

In the absence of the LRMC mechanism, the objectives for investment decision scrutiny would be picked up in the AoB charge before eventually transferring into the

deeper connection charge. (Despite the emphasis in the Authority proposal on motivating users to influence Transpower investment decisions, the focus of the proposed mechanisms is very much on re-allocating the costs of existing assets).

We assess the base option mechanisms in the following table which is constructed to simplify our assessment of the complicated combination of options, mechanisms and transitions.

Table 6 Assessment of options

Topic	Authority proposal	NZIER assessment
Base option	Reallocate HVDC and RCPD charges using three new mechanisms:	Primary focus is to re-allocate costs of grid assets based on potential use of existing grid asset capacity
	Deeper connection	Good in principle but complicated calculation process. Potential to increase allocation by lowering HHI.
	AoB	Principle of allocation based on option for capacity is sound but the estimate of capacity for EDBs appears to be high. Household capacity to use the grid is over-estimated however adopting a more realistic estimate need not materially alter the reallocation of charges. Treatment of industrials connected directly to the grid and those connected through an EDB is not consistent. EDBs pass-through charges to residential customers. This is neither a strong nor direct mechanism to encourage exposed EDBs to be more critical of Transpower investment plans.
	Residual	
Variations on base option	Include signals for planned investment cost or actual benefits from AoB assets	Trade-off between a better theoretical design and a modest change in the allocation of costs
	LRMC	Small reallocation of residual to cover the cost of planned investment. Minimal impact due to low forecast investment. Adds complication to the allocation process because of the different methodology used.
	SPD	Reallocation of the AoB charge to reflect actual rather than anticipated benefits. However no material effects on either the size of the residual or the AoB charge.
Implementation	Application A or B	Reallocate all costs or only costs of planned investment
	Application A	Reallocate of existing grid costs using a combination of deeper connection, AoB and residual charges
	Application B	Maintain status quo for allocation of existing grid costs and reallocate cost of planned assets based on
Transition	Phased implementation	Delays full implementation of the reallocation of costs by up to five years.

Source: NZIER

Regarding implementation, the proposed scope and the timing of how to apply the TPM re-allocation mechanisms imply a wide variation in the definition of the TPM efficiency problem. To illustrate:

- Applications A and B imply radically different estimates of the scope of the current misallocation;
  - Application A re-allocates a net $100m of all existing grid asset costs from direct connect industrials and generators to EDBs. This reallocation defines the TPM problem as 'inefficient and not cost reflective allocation of existing costs' where some EDBs and generators (except Meridian) are being cross-subsidised by direct connect industrials and Meridian[14]
  - Application B re-allocates a small amount of new asset costs only from mass market load and NZAS to generators (mainly South Island) leaving other direct connect industrials largely unaffected.[15] This reallocation limits the problem definition to the 'recovery of the cost of future grid investments from the expected beneficiaries of those investments'.
- Four transition options for Application A suggest varying degrees of urgency in correcting the current misallocation of costs:
  - two of the options propose an adjustment period for the costs re-allocated to EDBs as a group, before being finally allocated to individual EDBs in line with Application A.
  - the other two options phase in the changes by either capping the rate of increase or spreading the increase over 5 years.

All of the transition options start with an implementation of Application A in 2019.

4.3.2. The mechanisms in detail

Both the AoB and residual charges are allocated to industrial direct connect on the basis of AMD and to EDBs on the deemed capacity. The Authority rationale for allocating charges to direct industrial is that AMD is a proxy for these customers capacity and that a proxy is required because in some cases the installed capacity of the direct connect industrials exceeds their actual use.[16] The Authority calculates the deemed capacity for EDBs by multiplying the number of ICPS in each meter category by the Authority deemed maximum capacity of each meter category. The Authority acknowledges that this estimate of capacity actually exceeds the maximum load for some EDBs.

Our analysis of alternative measures of EDB capacity suggests that a more realistic estimate of EDB capacity would be considerably lower but would not eliminate the reallocation of grid cost from direct connect industrials to EDBs under the base option. Our analysis has not been able to confirm whether the Authority estimate of the capacity of large industrials connected to EDBs is accurate – that is whether industrials connected to the grid through EDBs are being treated in the same way as direct connect industrials.

[14] Although variants of Application A include an LRMC charge for new assets and beneficiary pays charges that exclude older assets, the residual re-allocates the balance of the total grid costs for each of the variants.

[15] Our examination of the re-allocation of costs under Application B has been hindered by the lack of data provided by the Authority in csv format.

[16] Paragraph 6.80 p44, however we note that this argument could equally be applied to EDB's and their customers.

A key issue for the effect of the re-allocation is how the EDBs will transfer the increase in costs to their customers, particularly households, and how these customers might respond.

Connection charges

The connection charges and loss constraint excess charges of approximately $200m per year are left unchanged under the Authority proposal as their cost is directly attributable to a single grid user. (We have not been able to find an Authority estimate of the value of these assets.)

Deeper connection charge

Deeper connection charges apply to approximately $2590m of assets and are set at approximately $330m. [17] The deeper connection charges are calculated using a three step process:

- a flow tracing algorithm is used to *identify the parties using the assets*. For the modelling in the options paper the Authority has apparently used two, three year periods 2009 to 2011 and 2012 to 2014.[18]
- a *share of use* (HHI) index is calculated for both generator and load customers from the average share of the flows across each asset. The HHI is used to determine whether the asset will be included in deeper connection charges for either generator of load customers. The Authority has chosen an HHI threshold of 5000 with a graduated cut-off for assets with an HHI between 4000 and 5000.
- the *cost related to the asset* (for three years) is calculated as 15 percent of the RAB value and is allocated to the generator or load using the asset based on their share of the AMD/AMI.

The following chart describes the total level of the deeper connection charge and the allocation of the charge between EDBs and generators. It also illustrates the sensitivity of the allocation to the choice of level for the HHI. The HHI of 4,500 shown in the chart is the mid-point cut off level used in the base case option. The maximum possible value of the deeper connection charge using this approach seems to be about $370m. Most of the deeper connection charge is incurred by EDBs where the cut off for the HHI band is above 4000. Most of the deeper connection charge is incurred by generators where the cut off for the HHI band is at or below 3500 from where the deeper connection charge allocated to EDBs falls in absolute terms.

Our sense from the options paper is that the Authority has chosen historical patterns of asset use to minimise the potential avoidance of the deeper connection charges. The comments in Appendix C of the Authority companion paper on the deeper connection charges suggest however that there are still some questions about the stability of the measure. Also, the complexity of the allocation approach makes it

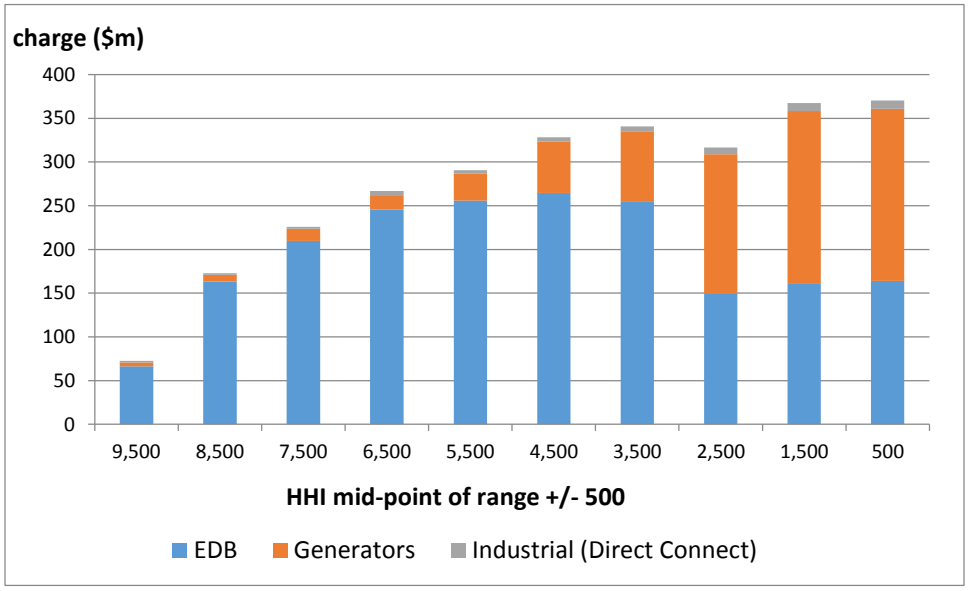
[17] This estimate is taken from the met is based on the spreadsheet 'Deeper_connection_working_-_assets_covered_in_Application_A_only_updated_31July2015' released by the Authority on 31 July and differs from the estimate of $315m indicated by the Authority in its correction to paragraph 11.31 of the

[18] They compare the flow tracing results from the two periods to assess the stability of the methodology and find there is little volatility in the classification of interconnection assets as 'deep' or 'true' interconnection assets from year to year. This is partly due to the choice of the graduated cut-off in the HHI from 4000 to 5000. However the comparison also shows that 30 percent of the nodes were not connected to the same assets in the two periods.

difficult to assess the strength of the incentives for grid users to invest in alternative assets or dis-aggregate some of their usage activities to slip under the HHI threshold.

Figure 1 Deeper connection charge level and composition

Variation in the deeper connection charge with change in HHI



Source: NZIER analysis of EA deeper connection data provided on 31 July

The remaining grid operating costs of approximately $470m are recovered through a mix of the AoB and residual charges. These charges are allocated to load customers on the basis of capacity (Authority deemed capacity for EDBs, AMD for direct connect industrial customers) and on MWh injection for generators.

Area of Benefit

The area of benefit charge is expected to recover up to $150m of costs and is a beneficiary pays charge applied to selected large assets (both economic and reliability) approved under a regulatory process.[19]

We see this charge as static rather than dynamic. The Authority expects that this charge will not be altered unless changes in benefits exceed a pre-determined threshold of a major change in flows, caused by for example a major permanent reconfiguration of the grid, a major new investment or the entry or exit of a major customer. The Authority proposal does not define these thresholds. The combination of the long review period for the deeper connection charges and the static nature of the AoB assessment suggest that once they are established both of these charges are unlikely to be responsive to shorter term changes in grid costs or use of the grid.

The following table summarises the selected AoB assets and the proposed allocation of the AoB charges across customer groups. The main change is the reallocation of approximately two thirds of the HVDC charge (Poles 2 and 3) direct to consumers and

[19] The charge is applied to assets approved or commissioned after 28 May 2004 that cost more than $50m and will apply to new investments approved after the publication of the TPM guidelines with a cost above $20m.

a change in the basis of the allocation of the costs among generators to MWh injection.

Table 7 Base option AoB

Reallocation of charges between generators and consumers

$m	Pole 3	Pole 2	LSI Renew	BPE-HAY	OTB-HAY	Wairakei Ring	Total
All consumers	$48.0						**$48.0**
All SI consumers		$9.9			$0.7		**$10.6**
All NI consumers		$31.4			$1.3		**$32.7**
Loads north of WKM						$6.5	**$6.5**
Total Consumers	**$48.0**	**$41.3**	**$0.0**	**$0.0**	**$2.0**	**$6.5**	**$97.7**
All NI generators				$4.0			**$4.0**
CNI generators						$6.5	**$6.5**
All SI generators	$32.0	$13.8		$4.0	$1.0		**$50.8**
All LSI generators			$27.0				**$27.0**
Total generators	**$32.0**	**$13.8**	**$27.0**	**$8.0**	**$1.0**	**$6.5**	**$88.3**

Source: NZIER analysis of 'EA dataset files\AoB\breakdown_of_area_of_benefit_charge.csv '

LRMC

The Authority proposes to use the marginal incremental cost (MIC) to provide price signals about the cost of future investment needed to accommodate changes in demand. The charge would be based on Transpower's 10 year demand and expenditure forecast for investments costing more than $20m. The charge would be applied at peak congestion and allocated on the basis of the net capacity required by a participant during congested periods.

The modelling by the Authority suggested the charge would recover $8m per year though this work excluded deeper connection investments and covered a period with forecast low growth in demand.

Our assessment of this variation is that the methodology for calculation the charge is likely to be difficult to apply in practice because of its complexity and that the signal sent by this charge is likely to be weak in comparison to the grid cost signals for at least the next five years. We suggest that the Authority weigh-up the complexity and cost of including this component in the TPM against the relatively weak signal it is likely to provide.

SPD

The Authority has suggested the use of SPD to allocate some of the AoB charge so that at least part of this charge is allocated on the basis of a dynamic (current actual) rather than a static (historical - when the investment was made) estimate of benefits.

We agree with their thinking. The modelling of the SPD was applied to Poles 2 and 3, the Wairakei Ring as well as the re-conductoring on BPE-HAY and OTB-HAY. Just over half of the costs of the AoB assets were recovered this way.

An advantage of the SPD is that it caps the recovery of the cost of the asset at each party's private benefit and implicitly adjusts for under use of capacity when the asset is first commissioned. To counter the risk of under recovery of the asset value by using depreciated asset values Transpower has suggested that the charge be based on non-depreciated asset value.

We do not support the use of non-depreciated asset values for the following reasons:

- the solution does not match the problem – that is, there is a mismatch between the timing of usage of the asset (which may or may not reach full capacity over its physical rather than its accounting life) and the accounting depreciation set by Transpower
- the issue of 'sustained under-utilisation' of assets – where the private benefits of the assets (over the life of the asset) are less than the costs that Transpower seeks to recover. This situation potentially applies to all of the charging mechanisms proposed by the Authority and is already dealt with in those mechanisms without recourse to non-depreciated asset values.

While we support the use of SPD in principle, again we suggest that the Authority weigh-up the complexity and cost of including this component in the TPM against the relative strength of the signal it is likely to provide.

Residual

The remainder of the estimated grid costs, about $322m, is recovered from consumers through a residual charge that is allocated to:

- EDBs on the basis of deemed capacity (sum of the number of ICPs in each meter category band multiplied by the maximum capacity of the meter in each band)
- AMD for direct connect industrials.

The Authority assumes a maximum capacity for a residential household meter of 20 kW[20] which is high in comparison to what we understand to be the average capacity of well under 10 kW. While the Authority assumption introduces an upward bias the paper does acknowledge that its estimate of EDB capacity substantially exceeds the maximum load of many EDBs.

We have used the Authority estimates of the allocation of residual charge based on alternative allocators - deemed capacity,[21] EDB capacity[22] and other EDB data such as transformer capacity,[23] to illustrate the effects on the allocation of the residual charge.

[20] The Authority assumes unmetered and category 1 ICPs have a 20 kW capacity. The assumed capacity for other meter categories are listed in paragraph a60 Table 12 p 109 of the Options Paper.

[21] Source: " Authority dataset files\Combinations\Caps_and_transitions\Workings_for_caps_and_transitions.xlsx"Workings_for_caps_and_transitions\Source data "

[22] Source: " Authority dataset files\Preprocessing\ICP_charge_calculations_-_by_customerxlsx"

[23] Source: Commerce Commission EDB Information Disclosure Schedule 9e

In the following table we compare the effect of different EDB capacity assumptions on the re- allocation of the residual charge from direct connect industrials to EDBs under the EA's proposed 'Application A Base Option':

- a change in the estimate of EDB capacity could increase the re-allocation of the residual to direct connect industrials by $6m to $15m.
- using EDB peak demand instead of an estimate of EDB capacity could increase the re-allocation of the residual to direct connect industrials by $45m – offsetting most of the re-allocation under the Authority modelling.

A change to the capacity measure used for the allocation of the residual charge would also affect the allocation of the AoB charge between the EDBs and direct connect industrials. If EDB peak demand was used as the allocator for both the residual and AoB charges we estimate the allocation of grid costs to direct connect industrials would be similar to the status quo albeit with a much more complicated basis for calculating the charge. The comparison in the following table is illustrative only. We do not have a preferred view on either the estimated capacity for Category 1 meters or the appropriate measure of capacity for other users.

Table 8 Sensitivity of residual charge to EDB capacity

Comparison of EA proposal with alternative estimates of EDB capacity

Entity	EA deemed capacity		EDB 10 kW Category 1 meter		EDB maximum transformer		EBDB 5 kW Category 1 meter		EDB peak demand	
	Cost ($m)	Share	Cost ($m)	Share	Cost ($m)	Share	Cost ($m)	Share	Cost ($m)	Share
EDB	$313.6	*97.4%*	$307.7	*95.6%*	$303.0	*94.1%*	$300.0	*93.2%*	$268.9	*83.5%*
Industrial (direct connect)	$8.4	*2.6%*	$14.3	*4.4%*	$19.0	*5.9%*	$22.0	*6.8%*	$53.1	*16.5%*

Source: NZIER

What matters from our evaluation of TPM changes

Conceptually, for us the mechanisms proposed by the Authority under Application A appear to have the potential to improve the clarity of signals to grid users and therefore to improve the efficiency of gird use and possibly investment decisions. The caveat on this statement is that the proposed changes still require current grid users to pay for unused capacity that may be due to:

- a timing mis-match between Transpower accounting treatment of asset depreciation and operating costs, and the benefits of the assets to grid users
- excess capacity in parts of the grid which may have resulted from over-estimation of demand from existing users, from the scale economies in lumpy investments or from changes in grid use.

The options paper provides sufficient modelling to indicate the direction and orders of magnitude of the reallocation of the grid costs under the base option and also to demonstrate how the charges might be calculated in practice.

However aside from describing the change with incentives for different grid users, the options paper is silent on how either grid users (EDBs) will change their approach to the recovery of grid costs from their end customers. Nor does it consider the way EDBs will approach influencing Transpower decision-making or importantly whether the reallocation of the charges will encourage Transpower to view grid investment differently.

The Authority propose a 5 year review period for the deeper connection charge to match the 5 year period of the price paths set by the Commerce Commission but does not appear to have considered the stability of flow tracing or the expected profile for asset usage in setting the review period.

Having said this – the 'winners and losers' are as follows.

Table 9 Winners and Losers

Re-allocation of cost between EDBs, generators and industrial direct connects

User	Increase in charges		Reduction in charges		Comment
	Entity	$m	Entity	$m	
EDBs	Vector	$107	Orion	$25	Net re-allocation of costs to EDBs of + $98m.
	Northpower	$19	Wellington Electricity	$17	
	Top Energy	$8	PowerNet	$6	
	Powerco	$7	Unison	$5	
	Westpower	$5	WEL	$2	
	9 other EDBs	$17	7 other EDBs	$10	
	EDB Increase	**$163**	**EDB reduction**	**$66**	
Generators	Contact	$15	Meridian	$49	Net reduction in generator costs of $24m. All generators except Meridian face increased costs
	MRP	$5			
	Genesis	$1			
	6 others	$6			
	Generator increase	**$27**	**Generator reduction**	**$49**	
Industrial direct connects	Norske Skog	$1	NZAS	$56	Net reduction in industrial direct connect costs of $74m All major industrials except Norske Skog face lower costs.
			NZ Steel	$7	
			Winstones	$3	
			CHH	$3	
			Pacific Steel	$2	
			5 others	$3	
	Industrials increase	**$1**	**Industrials decrease**	**$75**	

Source: NZIER

In simple terms the Application A proposal transfers more of the recovery of grid user costs away from industrial direct connects and Meridian to a handful of EDBs. The flow tracing mechanism, and to a lesser extent the AoB allocation, provide an objective test of the quantum of grid costs that industrial direct connects and generators were paying. Putting aside which allocator to use, for us this provides initial evidence that the Application A proposal offers a more efficient allocation of costs than the status quo.

In respect of encouraging greater scrutiny by EDBs of Transpower investment and more efficient use of grid assets by EDB customers, the benefits of Application A are less clear. The EDBs as a group were already paying the bulk of the grid costs and these costs already comprised a significant part of their own cost structure. Therefore, arguably, the EDBs already have a strong incentive to encourage Transpower to match investment to demand and to encourage their customers to use their distribution assets and to access the grid more efficiently. This subject should be a key focus for the CBA.

The bottom line for grid users of the combined mechanisms in the base case is illustrated in table 9 above using Authority analysis and data - which is based on historical grid use as we described earlier. We have concerns about this because reliance on historical data means that previous patterns of use are embedded in the allocation of future transmission. This also creates lags in the full allocation of costs of newer or high capacity assets where the usage profile is still building.

5. Implementation

5.1. Comparison of options

For us, Application A (Base Option) delivers the greatest progress toward an efficient re-allocation of costs for a given implementation cost. The two variations to the base option under Application A do not appear to be preferable to the base option for the following reasons:

- inclusion of LRMC offers minimal reduction in the size of the residual in exchange for the complexity of allocating the cost of planned investments and providing a very weak signal for the deferral of investment.
- Inclusion of SPD allocates part of the AoB on the dynamic benefits to grid users but introduces the issue of under–recovery of the cost of grid assets and the question of how these costs will be recovered.

We do not regard Application B as a preferable alternative to Application A because the re-allocation is minimal.

Accordingly we have narrowed our assessment of the practicalities of the implementation to the elements of the Application A Base Option. We also comment briefly on the proposed transition arrangements for Application A.

5.2. Application A – practicalities

The three main practical issues that need to be resolved for the implementation of Application A are:

- agreeing the methodology for the calculation of the deeper connection charge taking into account:
  - stability of deeper connection charges
  - agreement on the period covered by flow tracing and the process for resets
  - analysis of the trade-off between selection of a lower HHI (to reduce the residual charge) and the apparent preference to allocate grid costs direct to consumers rather than though generators
- clarifying the definition of 'capacity' for industrial direct connect and EDB customers so that:
  - the definition is near neutral for large industrials that are directly connected to the grid or connected through an EDB
  - the measure of capacity for EDB customers that are not large industrials is closer to the grid access that they can exercise as a group rather than individually[24]

[24] The access to the grid for EDB customers that connect directly to the grid is constrained by a combination of the capacity usage decision of other EDB customers and the capacity of the EDB to connect to the grid. While the theoretical capacity of household ICPS may be set at 20 kW for the EA calculations, EDB households cannot simultaneously exercise this option because it exceeds EDB transformer capacity. Also the EDB transformer capacity is likely to be a better proxy for the EDB demand that the grid is designed to meet than individual EDB customer meter capacity which is not visible to the grid owners.

- confirming the estimates of the timing of the changes required to support implementation of Application A to allow a more accurate assessment of:
  - the key areas of difficulty and uncertainty in implementation
  - how the length of the proposed transition options would compare to the time required to start implementation
  - the extent of electricity demand and supply, and grid investment and pricing changes that are likely to be prior to implementation.

5.2.1. Deeper connection methodology

The calculation of the deeper connection charge is a complex process apparently requiring a number of fine-tuning assumptions to both the flow-tracing and the application of HHI. The examples provided by the Authority and the precedents of other grid operators overseas using this approach provides evidence that the approach can be implemented. However for the deeper connection to deliver the signals sought by the Authority there needs to be a shared understanding between the grid operator, users and regulator about how the deeper connection charge is set and what behaviour it is expected to encourage.

For us the initial flow tracing for the deeper connection charge gave mixed messages about the volatility of the modelling. The Authority described this charge as 'stable' despite 30 percent of nodes being defined as connecting to different assets in the two three year periods used for the modelling.

The choice of the HHI cut off is critical. A more detailed explanation of the driver of the sensitivity as well as comparison of the expected effects of a lower HHI on the efficiency outcomes sought by the Authority seems to be needed for the next iteration of the analysis of the options.[25]

Understandably for a problem definition/options paper, the Authority proposal is not clear about the period to be used for setting and re-setting the deeper connection charge. In the next iteration we would be looking for more discussion on how the setting and reset processes should be aligned with the AoB and residual charge and how they should be affected by changes to the configuration or use of the grid. It would also be helpful if this discussion included comment from Transpower on how the new charging regime could be implemented and the Commerce Commission on how the regime could be co-ordinated with its IM reviews of Transpower pricing/investment decisions and EDB pricing.

5.2.2. Capacity measures

As we discussed in previous sections, the Authority definitions of capacity for EDBs seem to overstate the extent to which EDB customers have to access grid capacity. The Authority proposal observes the different approach but does not provide a rationale which may leave the proposal exposed to challenge.

[25] A lower HHI increases the deeper connection charge and allocates more of the deeper connection costs to generators rather than EDBs.

5.2.3. Timing

We understand from comments by the Authority that the earliest any of the proposals could take effect would be 2019. This implies that the mis-allocation of costs that the Authority is attempting to correct will have persisted for another four years before it is addressed and also that the assets to which the reallocation will apply will have depreciated by approximately 20 percent.

The time required to begin implementation of the re-allocation of charges should be considered in assessing the transition options.

5.2.4. Cost floor

The Authority describes a variable cost 'minimum' charge of about $250m that all grid connections will share. They refer to Transpower's variable costs as justification for this charge. We suggest that the basis for this charge and the definition of what is included as variable may be difficult to identify and categorise in practice. Our brief analysis of Transpower regulated costs provided the following categorisation and our allocation comments.

Table 10 Transpower regulated costs

Cost category	2016/2017 $m	Cost class	Comments re allocation
System operator	$38	Indirect	Share across all users - residual
Grid maintenance	$137	NW direct	Conn/Deep Con/AoB *
Operating – ***variable***	$11	Indirect	Share across all users - residual
Overheads	$151	Indirect	Share across all users - residual
Depreciation	$250	NW direct	Conn/Deep Con/AoB *
Capital cost (RAB x WACC)	$418	NW direct	Conn/Deep Con/AoB *
Regulatory tax	$39	Indirect	Share across all users - residual
Pass through	$27	Indirect	Share across all users - residual
EVA account	$12	Indirect	?
TOTAL	$1045		
			* Plus balance of residual

Source: Transpower RCP2 & NZIER

5.3. Transition arrangements

The discussion of transition arrangements for Application A in the Authority proposal does not seem to be strongly connected to the promotion of efficiency for the long term benefit of consumers that underpins the rest of the options paper. The starting point for the discussion is that Application A will create large changes that could be managed by a transition mechanism –smoothed over a period of two to five years. The rationale for smoothing these changes is unclear.

The lead-in time for the price change in 2019 should give the:

- EDBs and retailers time to prepare the customers for the prospect of increased costs
- Commerce Commission time to consider how the risk of re-allocation of grid costs could be allowed for in the price paths agreed with EDBs

There is no analysis comparing the expected size of the EDB cost increase to recent price increases (an indicator of political acceptability). Nor is there mention of demand elasticity (an indicator of consumer response and potential short term revenue pressure for EDBs who are partly reliant on consumption rather than capacity based charges) or tipping points for the take-up of alternative technology.

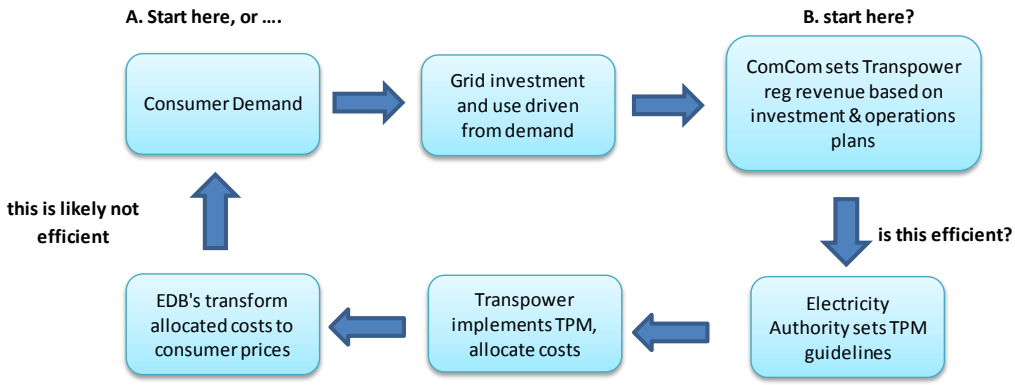
The smoothing mechanisms themselves simply phase in the re-allocation of costs and therefore perpetuate the current inefficient allocation of charging.

6. The regulatory jigsaw puzzle

Here we come back to a material source of inefficiency that the TPM review does not address - how Transpower regulated revenue cap is set for allocation to users. The nature, composition and size of this revenue over time impacts the efficiency of the TPM (the price for grid services). The grid IM's need to reflect the needs of both demand and generation over time – in other words the RAB (+ additions over time) needs to be 'efficient' in its own right if grid pricing is to be efficient.

This is not just the responsibility of the Commission but also of Transpower – the central planner. There are unanswered questions about the 'efficiency' of the RAB as it stands and how it is set (excess capacity and WACC being too high?) which already compromises the efficiency of the TPM and makes a difficult cost allocation task even more difficult.

Figure 2 Regulatory price setting



Source: NZIER

A. is the start point of the price setting process for a competitive model – that is consumer demand for services needs to be met in an efficient manner with asset and operational costs set to market. Capacity requirements need to be managed across consumer groups.

B. is the start point for price setting under a regulated model – that is regulated revenue needs to be recovered in an efficient manner. The level of the revenue to be recovered is a given while the impacts of how the EDB's transform their allocated costs into 'prices' is not considered a TPM matter even though there is a direct link back to the efficiency of the grid.

For us this is something of a 'missing link' which needs to be considered by both the Authority and the Commission as part of their reviews of Distribution pricing and Input methodologies that are underway.

In setting Transpower regulated revenue, the Commerce Commission has overview of the top 3 boxes while the Authority monitors the performance of the bottom 3 boxes. The intersection between these two processes, (the vertical arrows)

influences the efficiency of the whole system. We question whether these are efficient as they seem neither adequately monitored nor measured.

We also have concerns regarding how these TPM changes will impact the reallocation of risk between Transpower and the EDB's (and their customers). The beta for Transpower WACC calculation was originally based on the riskier earning streams of the EDB's which, in our view, ignores the risk reduction that Transpower earnings enjoy from the regulatory guarantee that it can recover its costs.

This approach to the recovery of Transpower costs from the users of the grid transfers the risk of both temporary and permanent under-use of grid assets from Transpower to the current users of the grid assets.

This is already a difficult competition/regulation problem for the Commission that will be exacerbated by the proposed TPM base option by:

- concentrating the recovery of the grid assets costs with a small number of North Island EDBs that are able to pass-through rather than carry the costs of transmission
- concentrating the increases in charges on residential household consumers that are least likely to increase their use of grid assets in response to the reallocation

Appendix A

Both the TPM options paper and the deeper connection charges companion paper include requests for comment by submitters on aspects of the options proposed by the Authority. This Appendix lists where and how this submission responds to the Authority requests for comment.

Table 11 Authority requests for comment- TPM Options paper

Authority paper section and comment	Summary of comment in this submission
1.91 The Authority would welcome submitters' views on whether there should be a transition in relation to Application A and, if so, what this should be. (p xv)	The discussion of transition arrangements for Application A in the Authority proposal does not seem to be strongly connected to the promotion of efficiency for the long term benefit of consumers that underpins the rest of the options paper. (See section 5.3.)
6.16 The modelling of proposed charges in this paper assumes that LCE is credited as suggested in paragraph 6.4 above. However, in relation to the proposal in paragraph 6.4(b), the Authority is interested in views as to whether it would be preferable to credit remaining LCE against only residual charges, given that residual charges are likely to be the most distortionary.	
6.80 The Authority is also seeking submitter views on whether the AoB charge for an investment should move to a congestion or peak-based charge once congestion is triggered for that investment, as is being considered for the deeper connection charge (see section 4 of the companion paper).	We argue against the addition of a congestion charge to either the AoB or deeper connection charge for the following reasons: • a combination of other options e.g. SPD and LRMC can provide a clear signal of the beneficiaries of current assets and the allocation of the costs of investment to improve capacity. • the congestion charge is complex and it is likely to be difficult to distinguish this signal from the other cost allocation signals.
6.94 The Authority expects that much of the base capex (which is around $250m per year) would be covered by these charges and that the benefit of providing an additional signal in relation to base capex through the residual charge would be low. The Authority would welcome submitters' views on whether a price signal through the residual charge is needed to promote efficient investment in relation to base capex.	We agree with the Authority's assessment. As stated in the submission we are sceptical that further reallocation of Transpower costs (largely from historic investments) will materially encourage more active critique of future Transpower investment decisions.
8.19 Transpower has suggested a modification to the SPD charge. Transpower has suggested to … the Authority could allow recovery based on the non-depreciated asset value. …. 8.20 … the Authority is considering adopting this approach and seeks submitter views on whether it would be an improvement to the SPD charge.	We suggest that the Authority should use the same measure of cost recovery across the charges (deeper connection, AoB/SPD and residual) being used to recover the cost of Transpower investments i.e. depreciated RAB.

Table 12 continued: Authority requests for comment – TPM options paper

Authority paper section and comment	Summary of comment in this submission
11.13 The Authority's preliminary view is that Application A is likely to yield greater net benefits. The Authority would welcome submitters' perspectives on whether they consider this would be the case. Issues with price increases would be best dealt with through transition mechanisms.	We agree that Application A materially alters the allocation of the recovery of Transpower costs while Application B barely changes the allocation of the costs from the status quo. The options paper does not provide a quantitative estimate of the net benefits.
12.15 The Authority would welcome submitters' views on whether there should be a transition and, if so, what this should be. The Authority has not formed a view about whether a transition mechanism should be adopted or, if so, which transition mechanism should be preferred.	The discussion of transition arrangements for Application A in the Authority proposal does not seem to be strongly connected to the promotion of efficiency for the long term benefit of consumers that underpins the rest of the options paper. (See section 5.3.)
14.15 The Authority is also further considering the impact of the potential TPM changes on electricity prices paid by residential consumers. Some submitters have suggested that any new dynamic pricing charges apply only to new assets and investments. This would have the advantage of avoiding substantial changes in the allocation of transmission costs, but would mean forgoing some potential efficiency gains. This would also require two charging regimes to be operated simultaneously. An alternative would be to adopt a phased introduction of any new charges. The Authority would welcome submitter views on these alternatives.	The comparison of Application A and Application B in the Authority proposal does not seem to be strongly connected to the promotion of efficiency for the long term benefit of consumers that underpins the rest of the options paper. Application A is suitable to addressing inefficient allocation of the costs of historic investments. Application A is suitable to preventing inefficient allocation of the costs of future investments. The avoidance of substantial change is not in itself a good basis for comparing the long term benefit to consumers of addressing the inefficient allocation of past or future investment costs.
C.11 The Authority would welcome comments on the best way to undertaken this analysis robustly, and any evidence submitters may have about the optimal SPD capping period.	

Source: NZIER

Table 13 Authority requests for comment - deeper connection charge

Authority paper section and comment	Summary of comment in this submission
4.29 The Authority is continuing to consider the relative benefits of the allocation options listed above. The Authority welcomes submitter views on which of the options would best ensure the allocation mechanism is well targeted and non-distortionary.	We support the allocation mechanism that both promotes efficient investment and is simplest to implement –option 2 based on AMI/AMD. In respect of the other options: • option 1 – allocate according to flow shares and option 4 – an allocation based on MWh injection/off-take are based on MWh charges do not encourage efficient investment for capacity. • option 5 – allocation based on number of ICPs and option 6 allocation based on a hybrid of per ICP charges for mass-market and $/MWh for direct connects seems less likely to encourage efficient investment in capacity than option 2 • option 3 – thermal capacity of connection assets sounds as if it will be difficult to apply in practice and also seems to conflict with the Authority's argument for using AMD/AMI for direct connects in allocating the residual charge.
4.31 The Authority also seeks submitter views on whether the allocation mechanism for the deeper connection charge should incorporate a signal about the cost of impending future investment. One approach would be to automatically adjust to a peak or congestion charge when congestion had exceeded a pre-set threshold that indicated an investment signal is required. While this may introduce additional complexity, it could promote efficient deferral of transmission investment.	We argue against the addition of a congestion charge to either the AoB or deeper connection charge for the following reasons: • a combination of other options e.g. SPD and LRMC can provide a clear signal of the beneficiaries of current assets and the allocation of the costs of investment to improve capacity. • the congestion charge is complex and it is likely to be difficult to distinguish this signal from the other cost allocation signals.

Source: NZIER