Transmission pricing methodology 2012

Evaluation of EA consultation paper

NZIER report to MEUG

28 February 2013

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Authorship

This paper was prepared at NZIER by David de Boer, John Stephenson and Chris Parker.

It was quality approved by Peter Clough

Version: Final

L13 Grant Thornton House, 215 Lambton Quay | PO Box 3479, Wellington 6140
Tel +64 4 472 1880 | econ@nzier.org.nz

Summary of our assessment

Major Electricity Users Group (MEUG) asked NZIER to conduct a targeted assessment of the Electricity Authority (EA) proposal for making changes to the transmission pricing methodology.

The EA problem

The EA has identified four sources of potential inefficiencies in the current transmission pricing methodology (TPM);

- inefficient investment and generation from HVDC pricing, $30 million PV
- for the interconnected HVAC grid about $45 million PV in dynamic inefficiencies and about $35 million PV from allocative inefficiencies
- about $22 million PV costs from suboptimal interconnected grid investment
- too much lobbying to have the TPM changed over time, because of dissatisfaction when people perceive that they pay more than they benefit.

The EA proposal

To address these issues the EA has proposed changes to the transmission pricing methodology (TPM). The most significant changes are to interconnection pricing and we have focussed on this. Currently, interconnection charges:

- collect all required revenue remaining after revenue from
  - charges levied on connection customers
  - HVDC charges levied on South Island generators
- are levied on consumers through a coincident peak demand charge.
- are partially off-set by the loss and constraint rentals (LCE) that are refunded to grid customers

The EA is proposing to:

- require Transpower to retain LCE and attribute these to links in the transmission grid
- use interconnection charges to collect all required revenue remaining after revenue from charges levied on connection customers (status quo)
- include HVDC costs in the calculation of interconnection charges

- charge the beneficiaries of interconnection assets based on benefits they receive from;
  - HVDC pole 2
  - other assets commissioned since 2004 valued at more than $2 million
- calculate benefits based on the 'scheduling, pricing and dispatch' (SPD) model using;
  - using half hourly demand and offer data as supplied by the market
  - solving for final prices under a counterfactual case where an interconnection asset is not available
  - calculating the extent to which consumers experience a reduction in cost and producers an increase in revenue
- collect any residual revenue required through a regional coincident peak charge
  - 50% levied on injection and
  - 50% levied on demand
  - with regions and peaks defined so as to incentivise efficient management of peaks.

Our assessment of the proposed interconnection charges

The proposed 'beneficiary pays' approach seeks to address three very different economic problems: the first is how to raise revenues to pay for sunk assets in the least distortionary way; the second is to be able to materially influence investment dynamics to improve efficiency in the sector; while the third is to address a currently under-priced free riding problem whereby the actions of grid customers affect subsequent transmission investment costs that are socialised to the whole market.
We agree with the EA that there are more efficient ways of pricing sunk transmission assets than the status quo that will encourage efficient future grid investment. We do not support many of the details of the EA proposal. However we welcome the openness to innovation in regard to transmission pricing and we see merit in the idea of linking transmission pricing to the wholesale spot market.

Future grid investments

We are supportive of the notion that this approach could lead to more efficient future grid investment compared to the status quo, provided that:

- the regulatory system for governing those investments is adjusted to facilitate such an outcome, and

- both the proposed SPD approach and any adjustments to the regulatory system are carefully developed to make sure that they improve the functioning of the market. The stakes are presently high. Two major factors (slack to declining demand and material increases in Transpower's regulated revenue) could combine over the next few years to disrupt the performance of the electricity sector regardless of changes to the TPM. It would be extremely unfortunate if the TPM heightened rather than alleviated these risks.

Sunk transmission costs

We are hesitant about the SPD method as the mechanism for efficiently recovering the costs of sunk investments due to a number of shortcomings that we perceive in the specifics of the EA approach.

- The methodology assumes that there will be no demand response from changes to transmission prices that will result from a new TPM. We see this as a major weakness because, over the longer term, grid users can, and likely will, adjust how they use the grid in response to charges. The SPD approach involves material wealth transfers that could well stimulate this behaviour. In section 3.2.1 we illustrate our concerns regarding this issue and how sensitive benefits are to the estimates of demand response.
- The SPD approach will not eliminate the avoidance of transmission charges. Parties who benefit from the grid will be identified and an assessment made of the extent to which they benefit. However, because the beneficiary pays portion of total charges under this approach is initially small [approx. 20% of the total revenue requirement] this means that for quite some years to come revenue recovery will be by way of a re-allocation of residual existing sunk costs.
- Pass through of the residual charges from generators to load will be difficult to avoid, however we contend that the benefits from the EA approach will depend crucially on the extent to which residual charges can be made to 'stick'. If they are simply passed through to end consumers then incentives to engage in investment processes will not improve a great deal. We are inclined to the view that over the long run all transmission charges will be borne by consumers anyway.
- The EA appear to have inadequately examined the treatment of the SPD approach on embedded generation and their discussion in the proposal document is inconsistent with subsequent explanations. Our understanding is that there are in excess of 160 such generation sites, with a variety of generation configurations,

suggesting to us that this is a material matter that needs particular consideration before a new TPM is considered and developed. To support consideration of embedded generation we suggest that any and all charges must relate to net injection or off take at the point of connection to the grid. This is the best basis upon which to measure the benefits of interconnection.

- There are a number of 'structural flaws' to do with the SPD methodology that, if not resolved, will lead to unintended outcomes which are likely to negatively impact the net benefits that the EA perceive could be delivered from the proposal. Significant amongst the structural issues are; the half hour capping period used in the benefits calculation that is instrumental in limiting the extent to which beneficiaries can be identified; the unorthodox calculation of consumer benefits that has the impact of overstating the quantum of the benefits; the 2004 cut-off date for inclusion of assets in the SPD scheme seems to be expedient.

Our Overall view – what matters most?

- As economists we are attracted to the proposal because, conceptually, it is a better approach to the TPM than the status quo and if structured appropriately and implemented to be durable it could improve the performance of the electricity sector. Having said that, the details of how it tackles a very difficult and complex issue makes it hard to see how it will be successful in its objectives.
- The EA's empirical analysis of costs and benefits is at best illustrative and leaves us unconvinced that the scale and scope of the purported net benefits will be realised.
- We also have concern that, if applied as is, the SPD approach will be unable to avoid precipitating material unintended outcomes that would likely result in a transmission pricing environment that is worse than the status quo. We suggest that the EA reconsider the SPD methodology as a whole and give attention to the issues that we describe in our assessment.

- The inclusion of HVDC pole 2 troubles us. We say this because of the likelihood that the HVDC HAMI charge has already been factored into SI generators asset values. If this is the case, then the current HVDC charge has no (or no material) impact on generation investment and consumer prices and there is no real resource cost , meaning that a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in dynamic efficiency.

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1. The current Transmission Pricing Methodology (TPM) is viewed by EA as being less efficient than it could be.
2. The economics and politics of the transmission business and its interactions with generation and load are complex which gives rise to considerable practical difficulties in the development of efficient arrangements to recover existing grid costs and to make new grid investments.
3. Work done on this subject by the EA and its predecessor over recent years has identified potential for efficiency improvements if changes were made to the TPM. For a variety of reasons, attempts at material change were not successfully agreed or implemented.
4. It may be that the peculiarities of transmission pricing preclude the use of market-based arrangements. Yet these same difficulties have clearly also made it extremely difficult to construct workable administrative solutions, at least in the case of interconnection [HVDC and HVAC] pricing.
5. The EA has thus proposed a pricing method which includes a market related mechanism and, wherever possible, is based on the principle that the transmission charges people face should be commensurate with the benefits they receive from transmission investment.

1.1. EA mandate and process

6. The motivation behind this proposal to change the TPM comes from the EA view that there has been a material change in circumstances since the current TPM came into force in 2008 and that suitably structured changes to the TPM would lead to improvements to the long term benefits for consumers. Clause 12.86 of the Code allows the EA to review the approved methodology on this basis. The EA is also of the view that the current HVDC and interconnection charges do not promote efficient transmission investment and will therefore continue to be the subject to legal and political challenge.
7. In May 2012, following public consultations, the EA published its decision making and economic framework for making changes to the TPM. NZIER provided MEUG with advice regarding the framework.[1] We viewed the EA high level decision framework as fit for purpose and endorsed the criteria for guiding code amendments as appropriate for assessing pricing approaches.
8. In their consultation paper the EA assess the lawfulness and practicality of each element of the proposal while the overall proposal is evaluated in terms of the

[1] TPM Framework Review NZIER report to MEUG 24 February 2012.

dynamic efficiency gains it could deliver and the quantum of benefits that could result over the longer term. These include:

- Better incentives to deliver efficient outcomes from better informed stakeholders
- Better investment and production decisions by linking costs to benefits
- More to gain from dynamic improvements over the longer term, and
- Diminished level of disruption and cost with the current TPM

9. While they do consider how the proposal could work in a practical sense, the application and implementation of a beneficiary pay approach is a secondary issue for the EA and the consultation paper seeks input on the proposed charging mechanism, how it could identify beneficiaries and quantify their willingness to pay.
10. It would seem clear from the proposal that the case to change the TPM is not up for debate and that a market like allocation/pricing mechanism will yield better results than the existing administrative methodology (EA have previously consulted on the principles that govern their approach to transmission pricing).

1.2. Problems with current TPM

11. The EA believes change is necessary because many market participants escape transmission charges, despite the benefits they receive from transmission services, while others pay beyond the benefits that they see. This undermines the durability of the current pricing regime and that the now agreed large increases in transmission prices up the ante in terms of lobbying for change and potentially negative impacts on consumers. In particular the EA believe that the efficiency of HVAC and HVDC prices under the current TPM are substantially inefficient.

Problems with HVDC Prices

For example, according to the EA the current HVDC charging method is problematic because it imposes costs on South Island generators which do not match the share of benefits they receive from the HVDC [Note that we refer here to Pole 2 and that the SI generators benefits do, however, exceed the HVDC charges they face]. The implications of this situation are that:

- investment in generation in the South Island is retarded, raising the cost of supply
- the mismatch between those who pay and those who benefit promotes lobbying, which allegedly undermines certainty about future transmission pricing and this undermines efficient investment in terms of both generation and load
- the HVDC charge, which applies to all South Island generation rather than select South Island plant that benefits from the HVDC, reduces investment in regions that are net importing regions and could possibly benefit from new generation (such as in the Upper South Island)
- it discourages investment in SI peaking plant
- it discourages SI plant from running at full capacity, as this potentially attracts a disproportionately high increase in HVDC charges because the HVDC charge is calculated on maximum injections.

12. The EA believes that the current situation leads to:

- insufficient levels of scrutiny of transmission investment resulting in inefficient consideration of investment alternatives and premature transmission investment decisions because:
  - beneficiaries can lobby for investments because those who do not benefit will have to pay a share of the costs
  - the costs of the investment are borne by a diffuse, opaque and limited number of market participants
- inefficient generation and load investment where;
  - generation investment accelerates transmission investment and the cost of that investment is not borne by the generator
  - new load accelerates transmission investment and the cost of that investment is not borne by load
- inefficient signals for load management which see;
  - consumers (in the lower North Island) unnecessarily shifting load out of peak periods
  - no signal to mass market customers to manage peak demand where it is efficient to do so

  - load reductions wherever charges do not reflect the relative value of transmission assets to consumers.
- The EA notes that forthcoming transmission price increases will exacerbate negative implications for efficient load growth. Inefficient load-related investment and load management could well dampen load growth. This would raise the cost of interconnection for other consumers and further worsen inefficiencies under the current regime.
- These issues could be analysed from a number of angles. One view is simply that life has turned out to be different to the future that formed the basis for the business case to invest in particular transmission assets resulting in a TPM that is more about recovering costs than setting transmission prices. While past investment decisions are sunk, the EA believes the issues described above are avoidable artefacts of the current transmission pricing method and that problems associated with the current HVAC interconnection pricing regime arise from the same fundamental source as problems with the HVDC charge: that is HVAC interconnection charges which are not commensurate with benefits received from interconnection assets.
- We note that, in proposing changes to the TPM, the EA is aiming to improve the pricing regime, not perfect it.

2. What the EA propose

13. The most significant changes are to interconnection pricing. Currently, interconnection charges:

- collect the net revenues required after revenue from
  - charges levied on connection customers
  - HVDC charges levied on South Island generators
- are levied on consumers through a coincident peak demand charge.
- are partially and indirectly off-set by the loss and constraint rentals (LCE) that are refunded directly to grid customers

14. The EA is proposing to:

- require Transpower to retain LCE and attribute these funds directly to links in the transmission grid
- use interconnection charges to collect all required revenue remaining after revenue from charges for connection services
- include both HVAC and HVDC costs in the calculation of interconnection revenue
- identify beneficiaries and calculate their benefits based on the system pricing and dispatch (SPD) model;
  - using half hourly demand and offer data as supplied by the market
  - solving for final prices under a counterfactual case where an interconnection asset is not available
- calculating the extent to which consumers experience a reduction in cost and producers an increase in revenue or reduction in cost from the exclusion of the asset[s]
- include the following in the definition of interconnection assets to which SPD is applied
  - HVDC pole 2
  - other assets commissioned since 2004 valued at more than $2 million
- collect any residual revenue required through a regional coincident peak charge
  - 50% levied on injection and
  - 50% levied on demand
  - With regions and peaks defined so as to incentivise efficient management of peaks.

15. The EA propose that the current charging arrangements for HVDC and interconnection be replaced by a new TPM that has several parts, with the material changes being;

- The addition of a beneficiary-pay charge for interconnection services (HVDC and HVAC), and
- That all parties connected to the transmission grid share the cost of any residual

16. The important questions of how to identify who benefits from use of transmission assets and how much benefit they receive is resolved by using data from the wholesale market, and the SPD settlement model, to calculate financial outcomes from the use of specific transmission assets. The calculations would be done in parallel to final pricing and invoiced to the beneficiaries that are identified through this method at the end of a billing period (monthly invoicing is suggested in the proposal).

Beneficiary Pays

The principle of beneficiary pays was considered as the preferred approach to allocating transmission charges by both TPAG and by the EA in its 2012 consultation on the TPM approach. After a first best market based pricing approach, beneficiary pays is becoming recognised as an acceptable to pricing at a conceptual level, however there are a number of aspects peculiar to the transmission business which makes the use of market-like pricing mechanisms, such as beneficiary pays, difficult to implement to the point that no one that we know of has gone down this path. It is also widely recognised that, to avoid stakeholder opposition, **all** beneficiaries need to be identified and that the regulation of cost allocation needs to be standardised and integrated into the transmission planning process to avoid the issues identified here from persisting into the future. These challenges make a beneficiary pays framework a complex task to design and implement.

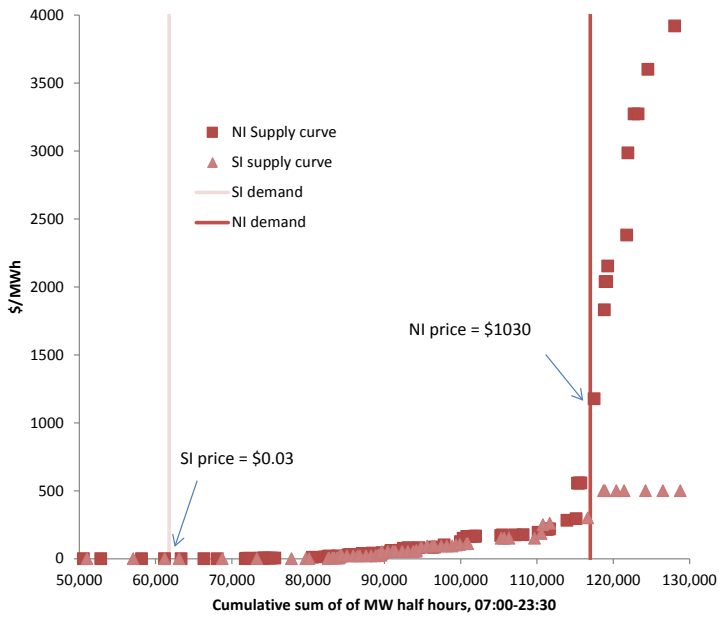
2.1. How benefit based charges work – an example

17. The EA proposes to determine market participants' benefits by calculating the magnitude of changes to both consumers' costs and generators' revenue in the absence of a particular interconnection asset (the SPD method). The methodology is complex but is most easily described with an example for the HVDC. Much of the benefits of the HVDC arise from South Island generation being able to be shipped to the North Island where most of New Zealand's demand resides. The principal effect of this is that consumers in the North benefit from lower prices and generators in the South benefit from higher prices.

2.1.1. Measuring benefits from the HVDC

18. Figure 1 shows North and South Island cumulative supply potential and offered market prices (i.e. supply curves) based on the average of offers from generators on 30 May 2011 during the high demand periods of the day (7am to 11.30pm). The vertical lines show standalone demand in each island during that period with **no HVDC** to transmit surplus generation to the North Island.
19. Without the HVDC the South Island price would be 3 cents per MWh for approx. 60,000 MWh of demand while the North Island would settle at $1030 per MWH for nearly 120,000 MWh of demand.

Figure 1 North and South Island markets without the HVDC

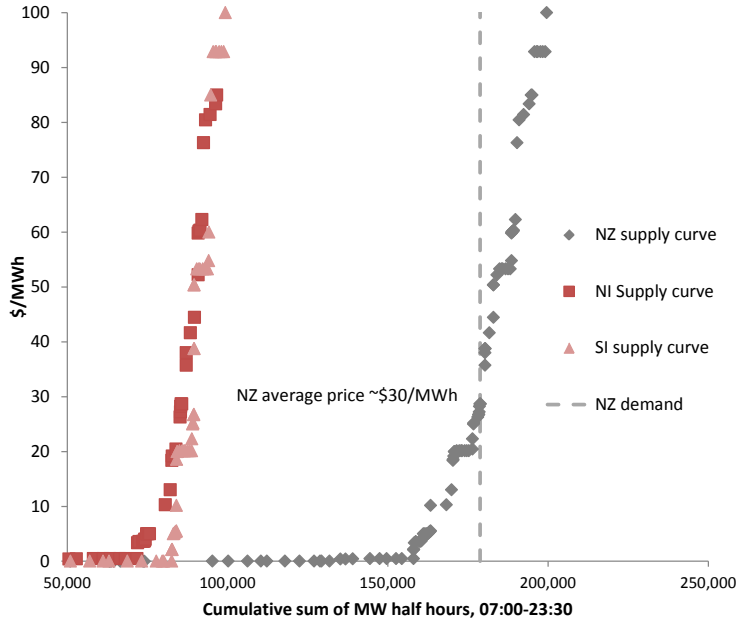


Source: NZIER

20. Figure 2 below shows the supply curves for each island, as well as the whole of New Zealand supply curve on 30 May 2011, with the HVDC link connected and transmitting power to the North Island. The cleared New Zealand volume is the vertical dashed line with a market price of $30 per MWh for nearly 180,000 MWh of demand. A number of matters are notable from this illustration using the HVDC but perhaps the most significant are that the EA analysis of benefits assumes that the generators offers will remain the same with and without the HVDC and that there will be no response from any class of consumers. We return to these issues later in our analysis.

Figure 2 NZ market with the HVDC

Vertical axis cropped at $100/MWh for presentational purposes. Data is 30 May 2011.



Source: NZIER

21. The following table summarises the changes to the financial situation for generators and consumers where, without the HVDC link, supply and demand would be matched within each market without any trade between the two islands. In the presence of the HVDC however, there is a dramatic change, with the New Zealand market now clearing at around $30/MWh, and identifiable winners and losers from the change.

Table 1 Per day change in benefits of HVDC Pole 2

	SOUTH ISLAND		NORTH ISLAND	
	No HVDC	With HVDC	No HVDC	With HVDC
MWh Price	3cents	$30	$1030	$30
Producers Revenue	$1000	$1.3m	$59m	Revenue decrease
Consumers Costs (inc reserves etc)	$1000	Cost increase	$65m	$2m

Source: NZIER

22. Beneficiaries are clearly identified (shaded in yellow), while for others there is a cost with generators in the North generators earning less and consumers in the South paying more (shaded in red).
23. These dynamics reverse when there is a deficit of generating capacity in the South and North Island power flows south. This situation existed on 15 March 2011, for example and the availability of the HVDC meant that:

- South Island consumers paid $3 million instead of the $11 million that they would have paid without the HVDC
- North Island consumers paid around $2.5 million more than they otherwise would have (from $1.5 million to $4 million)
- South Island generators received $2 million instead of $10 million and
- North Island energy generators revenue increased from $1.3 million to $4 million.

24. The essence of the EA's proposed beneficiary pays using the SPD method is that if there is a charge to be levied for the HVDC, it should be charged in proportion to these calculated benefits. (This exact same methodology would also be applied to all HVAC interconnection assets to identify and quantify beneficiaries.)

2.1.2. Converting benefits into interconnection charges

25. The steps to be followed in implementing the SPD method would follow the analysis of HVDC benefits illustrated above, although starting from a real world situation where the HVDC is available and then working back to see what would happen if the HVDC was not available. The system operator would analyse the price and quantity combinations that would be needed to clear the market in each island if there was no HVDC connection.
26. The total benefit of the HVDC would then be the value of the increase in cost of serving total New Zealand electricity demand in the hypothetical absence of the HVDC. The avoidance of this cost is a benefit which accrues to both consumers and producers, but not to all producers and consumers.
27. The calculation of benefits would be carried out for every grid entry and exit point and assigned to producers and consumers at each of those entry/exit points.
28. The calculation of benefits and benefit based charges would then have three further steps to it:

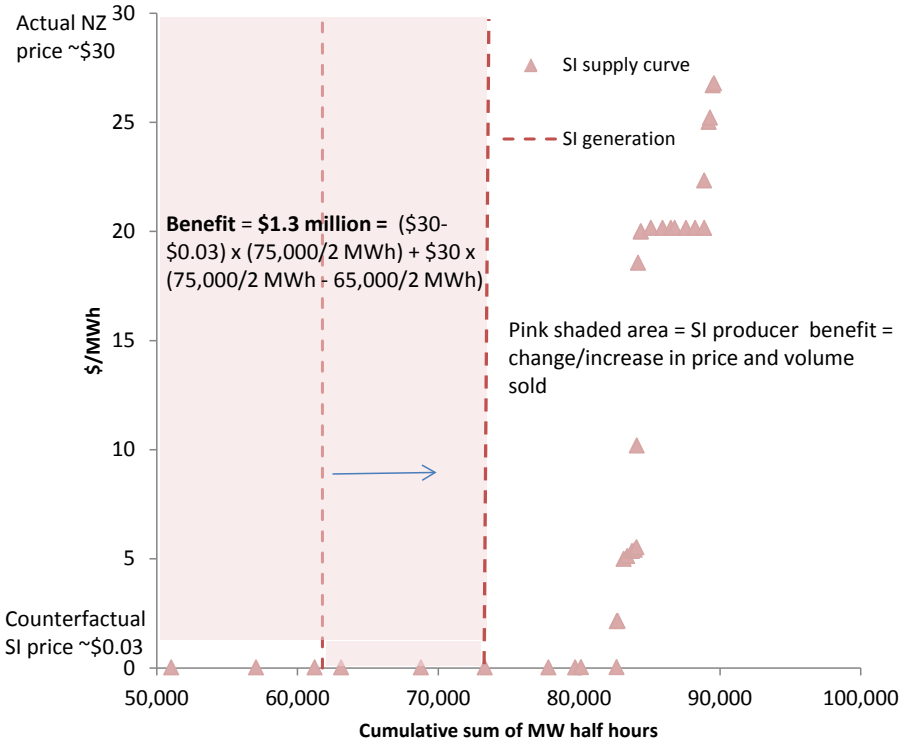
- the cost of production is subtracted from any revenue increase enjoyed by producers. This cost is estimated by assuming that prices offered by producers are equal to their costs of production so that the area under the market supply curve is assumed to be the cost of supply.

- consumer benefits are capped by a maximum price that a consumer would have to pay in the absence of the HVDC (or any other link) which is assumed to be $3,000 MW/h – approximately equal to the cost of electricity from a standby diesel plant.[2]
- total charges for any half hour are capped at the half hourly value (pro rata) of the required revenue for the HVDC, which means that either:
    a. beneficiaries are charged according to their calculated benefits in dollar terms or
    b. beneficiaries face a charge which is their share of the half hourly maximum charge in proportion to their share of the benefits.

29. We can calculate that the total maximum half hourly charge for the HVDC is $3,995 ($70 million annual charge divided by 17520 half hours in a year). Continuing with our example, and having identified the beneficiaries from Table 1 above, we can now calculate the chargeable benefits for South Island producers and North Island consumers, which is shown in Figure 3 and 4 below

Figure 3 Benefit of HVDC to South Island generators

Example of calculation for 30 May 2011, average across island from 7am to 11.30pm.



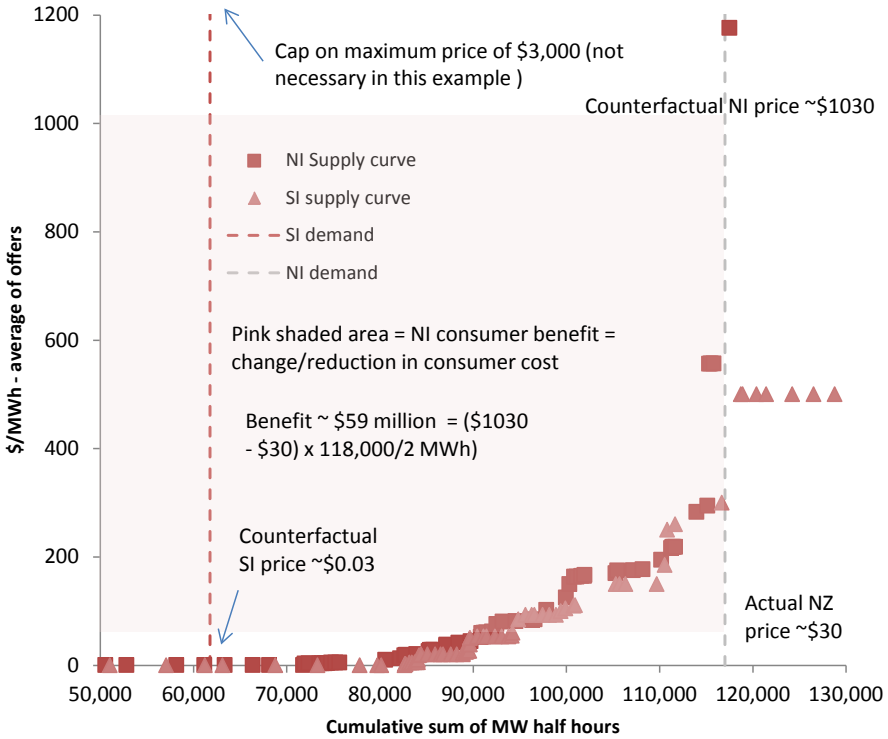
Source: NZIER

[2] This assumption is especially influential in the calculation of benefits because if it overstates the cost of the next best generation source then benefits to consumers will be accordingly overstated.

30. If benefit based charging had been in effect on 30 May 2011 half hourly benefits would have exceeded the maximum possible charge of $3,995 per MWh on all participants by quite some margin. In our example, benefits averaged $1.8 million per half hour. This causes the benefits based charge to be apportioned according to participants' relative shares of benefits. This would see South Island producers pay, in total, 2% of $3,995 per MWh and consumers to pay a total of 98% of $3,995 per MWh.
31. At a nodal level, consumers' delivered wholesale energy costs would increase by 7c per MWh and producers' charges would be 0.2 c per MWh.

Figure 4 Benefits of HVDC to North Island consumers

Example of calculation for 30 May 2011, average across island from 7am to 11.30pm



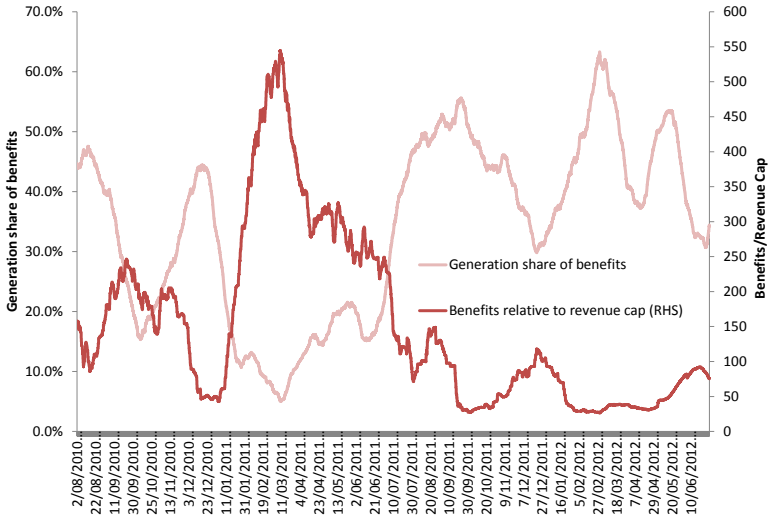
Source: NZIER

32. The SPD method will increase month-to-month variability of charges relative to the status quo. For most consumers this variability is unlikely to be large or problematic as it is limited in its variability by the fact that the majority of monthly charges will be the residual which will be set at the beginning of the pricing year.
33. Consumers with intermittent load or co-located generation could experience large variability in charges if demand and injection were not managed to avoid this volatility. It is important that the potential, and the impacts of this variability is well understood by consumers.

34. Consumers will typically benefit more from the HVDC than producers. However this will not always be the case as the rolling average analysis in Figure 5 below indicates.

Figure 5 Dynamic shifts in benefit shares

Rolling monthly averages



Source: NZIER

2.2. Relevance of a revenue cap

35. The proposed TPM caps the amount of charges in any given half hour. This will help reduce opportunities for inefficient avoidance of charges and reduce volatility in monthly charges but comes at the cost of under collecting benefit based charges and over collecting less efficient residual (RCP) charges.
36. A heavily used asset, such as pole 2 of the HVDC, facilitates large scale gains from trading across the network and as a consequence charges on the HVDC will strike the revenue requirement or maximum charge in most trading periods. This can be seen in Figure 6 below where the total benefits are many orders of magnitude larger than revenue requirement - peaking at $3 billion of benefits in the month of February 2011.
37. A half hourly revenue cap has the effect that the total revenue requirement for an asset will never be fully recovered through the SPD charge. This can also be seen in Figure 6 where SPD charges (the left hand axis) never reach the monthly maximum possible, despite the fact that benefits are so enormous, compared to the maximum SPD charge that we have to chart them on a separate scale (the right hand axis). The existence of several periods per day where benefits are below the revenue cap (typically off peak) means that the cost of the asset is never fully recovered.

Figure 6 HVDC benefits significantly higher than revenue cap

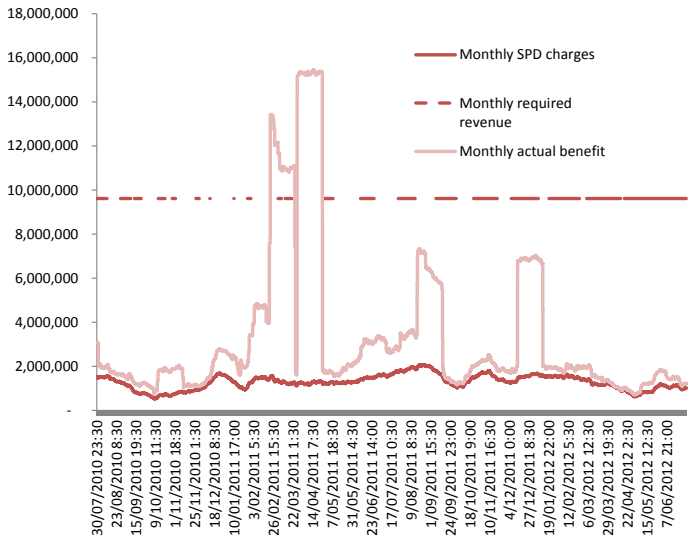
Rolling monthly benefits (right axis) and SPD charges, both in nominal dollars

Source: NZIER, EA

38. Use of the SPD approach for the HVDC that we describe here contrasts with estimates of the benefits from the North Island Grid Upgrade Project (NIGUP) - had that project been completed in the past two years. Figure 7 below shows that actual monthly benefits from this project rarely exceed required revenue and this situation, combined with the effect of capping revenue half hourly, means that less than 20% of the cost of NIGUP is recovered using the SPD method.

Figure 7 NIGUP benefit significantly lower than revenue cap

Rolling monthly benefits and SPD charges, both in nominal dollars



Source: NZIER

2.3. Direct incidence of proposed prices

39. The direct effects of the EA's methodology would be to shift a large amount of transmission charges from consumers to producers. This would, broadly speaking, see consumers face lower charges in the near term. However, those consumers with grid connected generation may well experience cost increases as grid injection would attract a cost where previously it attracted no transmission charges.

Table 2 Direct incidence of interconnection charges

UNI = Upper North Island, LNI = Lower North Island, USI = Upper South Island, LSI = Lower South Island. Includes HVDC charges. Status quo peaks and regions.

	Status Quo 2012/13		Status Quo 2015/16		Proposal 2015/16	
	$m	$/MWh	$m	$/MWh	$m	$/MWh
Load	555	13	733	17	476	12
UNI	187	17	247	22	162	15
LNI	183	12	242	16	157	11
USI	91	12	120	16	76	11
LSI	94	11	124	15	80	11
Generation	126	2	167	3	424	10
UNI	0	0	0	0	86	13
LNI	0	0	0	0	167	10
USI	66	7	87	10	83	9
LSI	60	8	80	11	88	10
Total	681	10	901	14	900	11

Source: NZIER

40. Table 2 provides an indication of changes to the direct incidence of interconnection charges as a consequence of the proposed methodology. Note that we have used demand and injection in the year ended June 2012 to

produce all of the figures below. The 2015/16 numbers therefore reflect the impact of increases in Transpower's required revenue.

41. Note that, under the SPD method, embedded generation can face some very high charges on a per (net) MWh basis if net injection is limited to periods where prices are high. Indeed, four nodes are excluded from the analysis in Table 2 because of high prices exerting an undue influence on the averages in the table (which are not consumption weighted).[3]
42. More generally, the impact of the proposed TPM on embedded generation is unclear. The EA appears to suggest, in places, that embedded generation could be charged on the basis of gross output e.g. 'if the charge was levied on all generation, it might be difficult to obtain output data for the smaller embedded generators' (5.6.87). We assume this is speculation about possibilities rather than a proposal as it would not make sense to charge embedded generators on the basis of gross output. If 100% of their output benefitted from interconnection, why would the generator be embedded in the first place? Charging on the basis of gross output would simply incentivise embedded generators to avoid the grid all together.

[3] The most extreme cases are that of offtake at the West Wind nodes in Makara (Wellington) and the Tararua Wind farm 220kv node where charges average more than a $1,000 per MWh; albeit on top of limited volumes. The other two nodes excluded are Halfway Bush (~$120/MWh) and Woodville (~$300/MWh).

3. NZIER analysis

43. NZIER were engaged by MEUG to conduct a high level assessment of the EA proposal to change the TPM to determine whether the proposal had merit and to give guidance as to the material matters in the proposal that warranted further analysis and assessment. The proposal flows logically from the economic and decision making framework for evaluating a TPM that the EA consulted on early in 2012.[4] It is developed from appropriate principles and it appears that the EA have put some effort into preparing analysis and materials for stakeholder communications and support, though the timeliness of the process and information availability has been challenging at time for what is a difficult subject matter. They have published a range of modelling results to help stakeholders understand how the proposal impacts them.

Transmission pricing involves major challenges

44. It is useful at the outset to comment on the challenges associated with pricing transmission services. The EA proposal is attempting to mimic the workings of a market – that is to identify who benefits from use of the transmission grid and therefore would be willing to pay for grid services. There are however a number of widely understood issues that get in the way of achieving this in a simple manner which have made the beneficiary pays approach unworkable in the past.

Positive look and feel

45. The proposal has some merit with the challenging task of identifying beneficiaries of transmission services, and the extent to which they benefit, appears to have been thoughtfully worked through by the EA. This is no mean task – we have been unable to identify any other location internationally where this objective has been attempted in this fashion. (We also tested the quality of the EA data analysis and modelling using market data from the last two years and our own SPD model. We use our own data and analysis in this report but can advise that our results and those of the EA are very similar. The EA work is of good quality but did not extend into areas that we believe are material to understanding whether, and how, the proposal can deliver net benefits. We have also independently reported to MEUG members on details of the trickle down effects of the proposal at grid exit and entry nodes).
46. The SPD approach may eventually turn out to be a more efficient approach than the status quo however we are of the view that it is imperative that the

[4] We note for the record that beneficiary pays is a second best solution in its own right with first best being market, or market like, pricing solutions such as the capacity rights proposal that NZIER has promoted over several years. That proposal was set aside on the basis of its higher set up costs. We wonder whether the complexity and potentially high implementation costs suggested for this SPD approach warrants a refresh of the costs and implementation arrangements for capacity rights.

EA 'get it right', especially at this point in time because of two major factors. Firstly there has been a measurable slackening of demand for electricity that may turn into a declining demand for transmission services, and secondly we should all be mindful of the material increases in Transpower regulated revenues that have been approved and will phase in over the next few years. Under these circumstances, transmission customers will be making less use of the grid and will be charged more for doing so. This will sensitise them to both the efficiencies of the TPM [whatever version it is] and the perceived inequities that result from the situation. Their behavioural responses will have material economic impacts.[5]

47. Our review of the EA proposal did not back track into the economic merits of the approach that were canvassed in 2012 but rather, we considered what in the proposal could be improved upon and what matters did we regard as significant that MEUG should give further attention to:-

    a. The EA problem definition
    b. The EA cost benefit appraisal
    c. Intended outcomes
    d. Unintended outcomes
    e. Pass-through of charges
    f. How embedded generation is treated under the proposal

Objectives for Transmission Pricing

As a reminder, the objective for transmission pricing could be identified as: ensuring that the combination of energy prices and network charges are levied on network users in ways that:

- Send efficient economic signals in the
  - Short term [for operating decisions]
  - Long term [for investment & location decisions]
- Recovers regulated costs of the network
- Does not discriminate
- Are easy to understand and implement

[5] The flow-on impacts were a major concern of the Federal Energy Regulatory Commission right throughout their consideration of transmission pricing in the US that resulted in Order 1000 that was delivered mid-2012.

Core issues

48. These objectives for transmission charges therefore need to balance two competing priorities:

    - the first is how to raise revenues to pay for sunk assets in the least distortionary way;
    - the second is to address free rider problems whereby the actions of grid customers affect subsequent transmission investment costs that are then socialised to the whole market.

49. Revenue recovery in an administrative system is a second best approach that should focus on the dynamic incentives to invest, i.e. the transmission owner will not invest without the prospect of a sufficient return on investment.
50. The challenge is to recover revenue in a way which minimises impacts on load, i.e. reduces the likelihood of load reduction in response to transmission charges. This is the same problem that governments and tax authorities face with tax rates. The conventional and well-established prognosis for dealing with this issue, to minimise costs to consumers, is:

    - to differentiate charges according to demand response i.e. higher charges on those who change their behaviour the least
    - if charges cannot be differentiated then the best way to minimise costs is to apply a low rate of charge to as broad a (tax) base as possible.

51. While least cost revenue recovery is all about minimising behaviour change, efficient price signals are all about promoting the right kind of behaviour change or the efficiency of investment decisions.

52. Therefore there are two very important and practical parts to this:

    1) ensuring that prices reflect the relative value of existing transmission capacity at different points in time and space
        - this is already reflected in loss and constraint rentals which rise and fall with demands on the grid
    2) providing signals about the extent to which production and consumption decisions can trigger grid investment, which then raise costs to all concerned (given the revenue recovery objective and the ideal pricing methods for meeting that objective)
        - charges should reflect the incremental costs of prospective transmission upgrades
        - future charges should be apportioned according to decisions which create costs.

3.1. The scope of the EA 'problem'

53. The EA has identified the following primary sources of potential inefficiencies in the current TPM:

- For the HVDC link, about $30 million PV, with 'considerable uncertainty', in dynamic inefficiencies from the peak charge (historical anytime maximum injection, or HAMI). It is caused by suppression of generation investment that is unnecessary given that there are minimal risks in inducing new grid investment prematurely (EA proposal Appendix C5)
- For the interconnected HVAC grid:[6]
  - about $45 million PV in dynamic inefficiencies from the interconnected grid relating to 'insufficient suppression' of generation and load activities that cause too much investment in the grid (Appendix D2).
  - about $35 million PV from allocative inefficiencies (Appendix D3), principally because end consumers do not end up facing capacity/peak charges (costs are passed through as a variable per kW charge) and even if they are passed through it is not clear that peak control is net beneficial.
- A lack of appropriate stakeholder engagement in grid investment appraisals because of a lack of 'skin in the game', with about $22 million PV costs from suboptimal interconnected grid investment (section D2.2), and an un-quantified amount for HVDC investment (e.g. paragraphs 4.3.8 and 4.3.10.b)
- Too much lobbying to have the TPM changed over time, because of dissatisfaction when people pay more than they benefit, which wastes resources and creates regulatory uncertainty (e.g. paragraphs 4.3.11, 4.4.6.c, and 5.6.55.e).

54. We are in agreement with many of these findings, in particular the inefficiencies associated with RCPD pricing and the fact it does little to address the free rider problems which result in dynamically inefficient investments.

3.2. The EA cost-benefit appraisal (CBA)

Key CBA results and the EA's method

55. The EA estimates an NPV of about $158 million for benefits from the HVAC and HVDC part of this proposal, with dynamic efficiency benefits of about $172 million PV, reduced costs of disputes of about $36 million PV, and implementation costs of about $50 million PV.

[6] The EA also discusses whether there are dynamic efficiency benefits from appropriate suppression of generation and load activities from the RCPD. They find no evidence of its significance (section D3.5).

56. Overall the EA's CBA is intuitively plausible, but is not well evidenced. This is particularly so for the assessed dynamic efficiency gains. We view this part of the CBA assessment as a quantitative illustration of what the benefits might be if dynamic efficiencies were to occur. It is not a probabilistic assessment of the welfare gains expected to arise, which is what we would have expected to see.
57. The CBA methodology used by the EA is practically guaranteed to provide a net benefit because it simply asserts that there are dynamic efficiency gains, and applies a mark-up factor (of 0.3%) — one not dissimilar to other arbitrary mark-up factors used in the past by reputable entities — to the future growth of the market.
58. That said, the ~$100 million PV dynamic inefficiencies estimated in the EA's problem definition work is considerable and the analysis behind this was more thorough than for the CBA itself, leaving us to wonder why the methods in the CBA do not connect better with those used in the problem definition.

3.2.1. Intended outcomes – allocative efficiency

59. Using the beneficiary-pays concept as a guide to willingness to pay and hence to raise revenue to pay for sunk investments could be seen as efficient to the extent that, like Ramsey pricing, it has the effect of reducing allocative inefficiencies.[7] Transmission charges are applied more heavily to those that are estimated to benefit more with the implicit assumption that those that benefit more will also be the least price-sensitive to charges. If it turns out that this does not hold then the beneficiary-pays approach may be more distortionary in a static efficient sense than flat energy charging.
60. The beneficiary-pays concept is also likely more efficient than alternative methods to the extent that, by using wholesale market data, it appropriately accounts for the various price sensitivities (i.e. price elasticities) of load and generation at each time and location. Grid customers will, however likely reduce their demand for the grid. To a greater or lesser extent they will consume or transmit less power at peak times, and over time they will invest in ways to avoid their grid demands, and thus their charges. Because transmission revenues requirements will continue to increase, this means that other grid customers will face correspondingly higher charges. Although these distortions are welfare costs, they can be minimised to the extent that the charges are appropriately set to be relatively higher to those that are less price responsive.
61. At the same time, the benefit calculation methods applied by the EA fails to account for people's actual willingness to pay —because the method deploys assumptions of perfectly inelastic demand schedules — and this means that

[7] Because these are taxes deadweight losses cannot be eliminated.

the proposal risks doing more harm than good (see our discussion below on consumer benefit calculations).

62. Deadweight losses (in a static sense) would be too high because the charges are not appropriately calibrated to the various demand elasticities. Those that are charged too highly will reduce their demand by too much, and will over-invest in ways to minimise their grid demands, and thus their taxes. The more taxes are avoided, the more revenue must be shouldered by everyone else, which exaggerates the extent of deadweight losses being unnecessarily high.

Our estimates

63. To illustrate our concerns we have considered the benefits of the proposed TPM against the current TPM in the case of NIGUP. We focus on NIGUP because it represents the largest driver of current transmission price increases. A straight forward and conservative estimate of the allocative efficiency benefits of the proposal shows that it is beneficial (without accounting for the costs of implementing the proposal) but the benefits are not large starting from $3.2 million dollars (present value).[8]
64. The allocative efficiency gains that occur under the proposed TPM result from:

- spreading welfare losses across generators and consumers (i.e. broadening the tax base) and
- differentiating charges so that those who do benefit from the asset are paying more for the asset.

65. Welfare losses from NIGUP arise from annual charges ($116 million) being in excess of measured market benefits ($17.6 million per annum as compared to $9.7 million accruing to consumers).[9]
66. Our assessment of the quantum of these losses is based on the SPD method examples used by the EA, but adapted to include a modest demand response in the consumer benefit calculation (price elasticity of demand of -0.01) and assuming that all RCPI charges are fully passed through to consumers but that generators share of SPD charges are not passed through at all.
67. The gap between benefits and charges results in a present valued loss of welfare in the order of $111 million over 3 years, including the assumption that net costs of NIGUP will decline exponentially to the point where they are trivial within three years (see Figure 8).
68. We note here that the benefits of NIGUP do include system reliability benefits that are not included in our calculation and also that we would expect the benefits of NIGUP to increase rapidly and non-linearly if demand increases.

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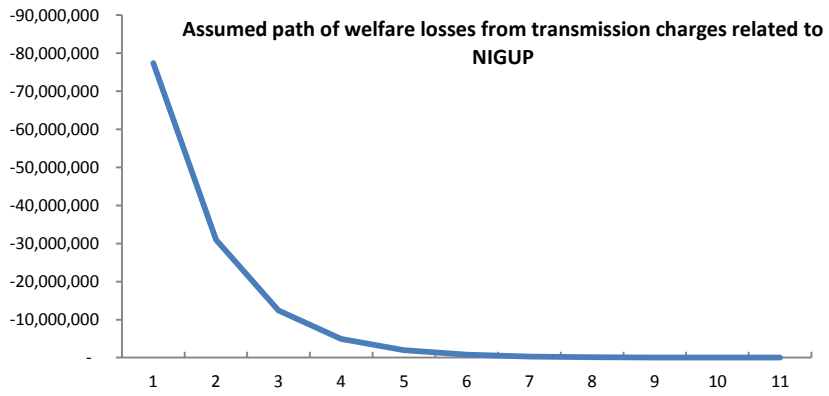
[8] Our simple approach is illustrative. It is a partial analysis. It is, however, reasonable in the sense that we are interested in orders of magnitude of benefits or losses in terms of comparing the two TPMs.

[9] Gross benefits, including negative benefits are $7.9 million to consumers and -$14.7 to generators yielding a total loss of $6.8 million.

Still, we think that it is unlikely these factors would significantly close this $70 million gap between benefits and charges in the near term.

Figure 8 NIGUP Welfare losses



Source: NZIER

69. We believe this evaluation understates the welfare losses, in terms of the costs of NIGUP and the benefits of the proposed changes to the TPM, because we have not considered:

- the extent to which demand response raises all interconnection charges and
- the fact that NIGUP related charges come at the same time as interconnection charge increases to recover revenue for other projects,

70. We believe that these factors would increase both demand response and welfare losses.

Elasticity assumptions

If we relaxed some of our conservative assumptions the results change significantly. For example, if we assume a price elasticity of demand of -0.1 (up from -0.01), that the SPD method includes a single 24 hour revenue cap (48 trading periods) and that losses take 10 years to decline to trivial levels, then:

- consumer welfare losses rise to $633 million (present valued over 10 years)
- consumer welfare loses over the next 3 years are $463 million under the current TPM
- the proposed TPM lessens consumer losses by $20 million (over that 3 year period)

71. The fact that the SPD method has allocative efficiency benefits is important, as is the fact that these gains are not especially large, when compared to the costs of implementing the SPD method. However neither of these matters should tip the scales for or against a change.
72. As should be apparent, the key assumption is the speed at which NIGUP delivers benefits commensurate with its charges. In other words, the benefits of real importance are matters of dynamic efficiency and they are potentially very large.

3.2.2. Intended outcomes – dynamic gains

73. We agree with the EA's assessment that there are dynamic inefficiencies in the current TPM. We believe the EA's proposed TPM is likely to improve on this. We are, however, unsure how big that improvement will be. A considerable amount of our uncertainty comes from flaws in the particulars of the EA's proposal.
74. Investment in generation plant and new factories by electricity consumers (load) can cumulatively impact on when grid investment becomes economically viable. At present the costs for this are raised from RCPD charges on load.
75. Although good grid investment approval processes will help ensure that any given grid investment undertaken is still economic, improved price signals are needed to more efficiently manage any need for grid investment and improve decision making processes and timing of new investment.[10]
76. There have been several attempts to identify a practical approach to long run pricing of transmission investment. Covec (2004)[11] suggested creating a new price signal relating to participants contribution to the deferral or acceleration of the need for grid expansion. Their specific approach was illustrative and sought to be revenue neutral. Covec said it was unlikely that the complexity was justified given the extent of the locational signalling problem.
77. Frontier Economics (2004)[12] acknowledged the issue of incorporating a location signal to reflect the long-run (investment) cost implications of growing network use (page iv). But they thought introducing an explicit *ex ante* price (i.e. before future grid investments were committed) that related to LRMC of future grid upgrades would be fraught with difficulties (pages 26–27). Frontier said that such prices would trade off allocative efficiency against dynamic efficiency; would require substantial amounts of information and analysis; may change in

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[10] This point is raised, for example, by the EA in paragraph 49 on page D12.

NERA highlighted the desire to provide price signals to address similar issues (even though NZIER previously, and rightfully, criticised that aspect of the report for suggesting long-run marginal costs of capacity expansion projects has major patterns of up and down cycles); section 2.3 of NERA (2004) *New Zealand Transmission Pricing Project*; Report to the NZ Electricity Industry Steering Group.

[11] Covec (2004) *Locational signals for new investment*; report to the Electricity Commission.

[12] Frontier Economics (2004) *Transmission pricing methodology – options and guidelines*, Report to the Electricity Commission.

real time as patterns of generation, load and grid networks evolved; and it would create governance and regulatory oversight issues.

78. On the face of it, the ambitious SPD modelling framework proposed by the EA would overcome at least some of the difficulties described by others in attempting to construct a durable solution to long run pricing of transmission investment (see, e.g. Box).
79. If a grid customer invests in a location and that investment will likely bring forward a planned network upgrade by some number of years, then expected future costs will increase in PV terms. Under the proposed SPD method those who benefit from the new asset will be charged accordingly and, as long as the benefit calculations are reasonable and realistic, no one should object to these charges.
80. More importantly, those who do not benefit will not pay benefit-based charges and would therefore be less likely to lobby for investment delays or to inefficiently reduce load to avoid charges for assets of no benefit to them. SPD modelling of benefits clearly shows that under the current TPM a number of consumers are set to pay charges well in excess of their benefits and that therefore the risk of inefficient load reduction is a very real problem. Others who are benefitting from existing asset configurations will be wary of changes to the status quo.
81. At the same time, the SPD method is unlikely to recover dynamically efficient levels of revenue i.e. revenue required to ensure sufficient incentives to invest in new transmission. This means there will remain a portion of costs, the residual, which will be 'socialised'.
82. How this 'residual' charge is constructed will matter a great deal for dynamic efficiency, especially as the less beneficial an investment is the higher will be the residual. The EA has not explored this in any great detail. Although the intention to spread costs across a wider base than the current RCPD charge (i.e. including generators in addition to consumers) is useful given that it will (reasonably) increase the number of parties affected by transmission charges and this should improve decision making. Quite how much decision making might improve and the quantitative benefits of this are unclear. They will depend crucially on the extent to which residual charges will 'stick'. If they are simply passed through to end consumers then incentives to engage in investment processes will not improve a great deal. Other considerations relating to RCPD/RCPI and how it might be improved are discussed further in paragraphs 120 to 126.
83. Other important questions as to how effective the EA approach will be in causing consumers and generators to consider the impacts that their decisions could have on future transmission investment and to engage in investment decisions include:

- How sharp or dull is the incentive given that the charge would be shared with other grid customers at that grid exit point (GXP) (we encourage the EA's consideration of this issue in terms of how distributors pass on charges).
- To what extent would grid customers have enough knowledge of the future workings and conditions of the grid to appropriately perceive the effects caused by their actions (or inactions)?[13]
- Is sufficient information available on customers' willingness to pay in the derivation of their benefit shares? That is, will an appropriate demand schedule be used, or will a vertical demand schedule be used? The less that is known about willingness to pay, the greater the risks of overcharging customers and (worsening) deadweight losses.

84. There is also a follow on issue that could impact behaviour changes. As it is primarily peak use of a network that drives the need for capacity expansions the beneficiary-pays approach could reasonably be expected to influence grid customers' behaviours primarily in the peak period. This reduces the importance of regional coincident peak pricing to raise residual revenue.
85. It is important to note at this point of our analysis that without reasonable-sized dynamic gains, the EA's proposal may well not stack up at all. There would be $36 million PV in 'durability' benefits (Appendix F, page 15), $22 million PV in benefits from improved 'scrutiny of grid investments' (section D2.2), and no further dynamic efficiency benefits from the RCPD/RCPI approach over and above what would occur in the base case. The net benefits of $58 million would then be sufficiently close to the costs of $50 million PV to cast reasonable doubt on the economic efficiency of the proposals.

3.2.3. Does the CBA reflect a 'fair deal'?

86. MEUG members asked NZIER for clarification on whether the CBA appropriately reflects all of the various costs to consumers, and whether issues of 'fairness and reasonableness' are addressed, if at all. There is a question of whether any premium of sorts may be afforded in a CBA to impacts that fall disproportionately to certain types of stakeholders. For instance, if owners of embedded generation were to pay more, relative to others, to the extent that

[13] The proposal relies on grid operators and regulators foreseeing the impacts they cause to grid investment. If it is too hard for them to do so then the proposal will underperform.

This raises some related questions, such as: if customers are judged to be sophisticated enough to understand the effects on future grid investment (or can rely on sufficiently sophisticated forecasts by a third party), then arguably so too should grid operators? But if grid operators could do likewise then what is stopping them from explicitly pricing these effects in advance of grid commitments being made? If they could then they could raise a relatively distortion-free rent that obviates the need for taxes to cover residual revenues.

some consider unfair, then what scope is there for that to be considered appropriately by decision makers?

87. The first observation is that the EA's Code Amendment Principles centre squarely on 'economic efficiency' (Principle 2), and so there is no straightforward avenue to engage in notions of fairness and reasonableness. We note this is in contrast to the FERC Order 1000 which requires that non-discrimination and equity requirements be considered when developing cost allocation methodologies for transmission services.
88. Nevertheless, even if the focus is solely on economic efficiency, there is scope for considering equity in efficiency appraisals. It would entail placing different weights on the impacts of stakeholder groups — rather than the conventional assumption of assuming equal weights for all stakeholders regardless of context.[14]
89. The area is difficult because it necessarily involves subjective value judgements. However, these judgements clearly matter given that participants are more likely to lobby for change or engage in legal action, or simply avoid transmission charges, if they feel aggrieved over the reasonableness of the transmission charges they face. Furthermore, the EA opens the door to considerations of equity in so far as they see gains from reduced lobbying and greater regulatory stability which, if achieved, will partly reflect the perceived fairness of benefit-based charging.
90. Indeed, the reallocation of sunk costs under the EA's proposal through the introduction of RCPI charges and an SPD charge for HVDC pole 2 will doubtless leave some feeling aggrieved. Some will lose money on past investments made in the expectation that the regulatory environment would not change significantly. Others will gain. This kind of transfer matters little for a simple cost benefit analysis. However the fact that some are aggrieved could contribute to a sustained mistrust in the regulatory regime and a consequent sense of uncertainty that will not assist in the efficient long term development of the industry to the benefit of consumers.
91. The EA has suggested that their proposal will improve regulatory certainty and stability. Although it is hard to see that the EA's proposal would worsen uncertainty to any great degree, we are not convinced that stability and certainty will improve. Only time will tell.

[14] Weighting everyone equally follows from the *Kaldor-Hicks criterion*, where a policy should be adopted if and only if those who will gain *could* fully compensate those who will lose and still be better off (even if they do not actually compensate losers).

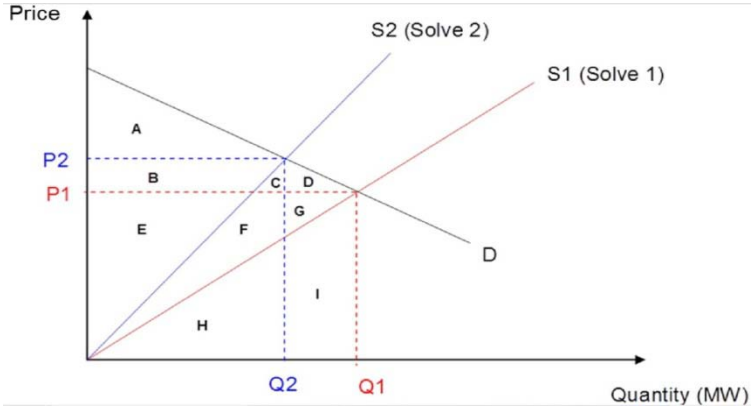
3.3. Implementation issues and unintended outcomes

92. Our review identified a number of matters that we considered material enough to impact the integrity and success of the proposal [ie; they could produce unintended negative outcomes], and that appeared to have a high probability of doing so. As we have indicated the beneficiaries approach is considered as conceptually sound but would likely be structurally complex and difficult to implement, which is possibly why it has not been implemented anywhere else in the world.

Issue – consumer benefit calculation

93. The proposed calculation of consumer benefit requires adjustment. It must be amended to include a more realistic characterisation of demand in the benefit calculation. This should include the use of a downward sloping demand curve in the calculation of consumer benefits (i.e. incorporating the sensitivity of load to sustained price changes). The EA has illustrated what this might look like in its description of how the SPD method might work. This is shown in Figure 10, taken from Appendix E of the consultation document.
94. The EA notes that the benefit consumers receive from an interconnection asset is the additional consumer surplus in the combined area B+C+D. This is a fairly conventional, albeit a very simplified, way to measure consumer benefits.

Figure 9 EA illustration of calculating benefits



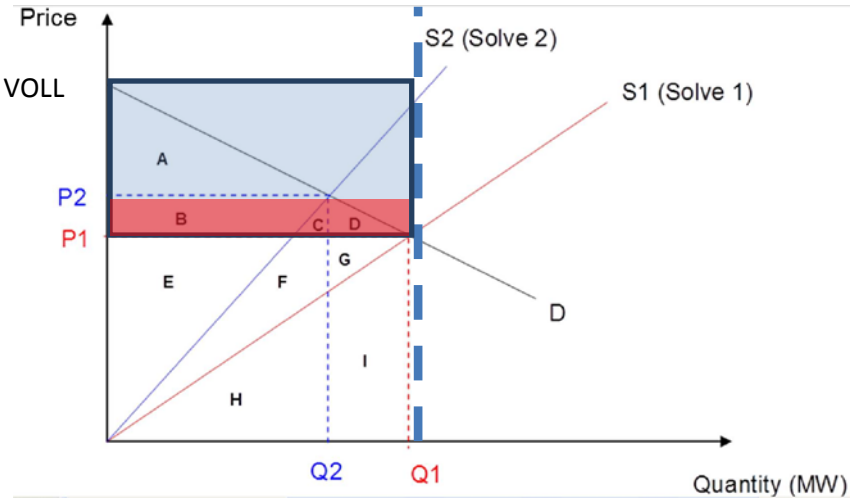
Source: EA Consultation Paper, 10 October 2012, page 91

95. The calculation method the EA has proposed is, in practice, not like Figure 9. The EA has proposed that consumer surplus be calculated as a rectangle which is equal to the difference between (a price referred to as) the value of lost load (VOLL) and the prevailing market price multiplied by the quantity of demand. This is shown by the blue rectangle superimposed on the EA's diagram from

Appendix E, figure 10 below. The superimposed dashed vertical line represents the implied shape of the demand curve that the EA is using to calculate benefits.

96. The benefit that a consumer receives from an interconnection asset is then calculated as the change in the size of this rectangle. The change in the size of this rectangle is simply the change in price (P2-P1 in figure 10) multiplied by the quantity of demand (which is unchanged under the counterfactual). The resulting 'benefit' is the area of the red rectangle shown in Figure 10.

Figure 10 EA proposed calculation of consumer benefits



Source: EA Consultation Paper, 10 October 2012, page 91

97. The EA's proposed benefit calculation amounts to assuming that there would be no change in demand even if prices are very high under a counterfactual scenario without a major interconnection asset (such as the HVDC).
98. The EA has not given any reasons for this assumption. We suspect the reasons are that (a) the calculation is for benefits in real time and that there is very little demand response in real time (b) if a downward sloping demand curve was used in practice it may be difficult to determine the appropriate shape of that curve and (c) that allowing for demand response could make the counterfactual solve more difficult by requiring a redetermination of demand. While it would be convenient to avoid these kinds of 'wrinkles' the EA's approach must be improved. While consumers cannot, in practice, adjust their demand in real time in response to prices, this matters little for measuring the benefits that consumers receive from consuming electricity.
99. The benefit to consumers of lower prices is (approximately) the difference between what the consumer would be willing to spend – the counterfactual – and what the consumer factually spent. The EA has proposed that the relevant willingness to pay is VOLL. While it may be true that consumers express a high

degree of willingness to pay to avoid an outage for any given half hour, it is a fallacy (of composition) to assume that this is true over time or for repeated half hours.

100. The VOLL aspect of the current SPD calculation has already taken account of this. The proposed value of $3000 per MWh reflects an appreciation for the difference between consumer demand and consumers' stated willingness to avoid low probability, short duration, high impact events where load is lost altogether.

101. Even then $3,000 per MWh, as the maximum price that every consumer would be willing to pay without adjusting their demand, overlooks the fact that for many consumers the price at which demand would sink to zero is more likely to be in the order of $300 than $3000 per MWh. Income constraints also point to the infeasibility of full demand at $3000 per MWh. The EA's calculations imply that consumers would be willing to pay in the order of $114 billion per annum on electricity (38 million MWh x $3000). This amounts to 80% of total gross national disposable income in New Zealand (approximately $140 billion).

102. The EA should also put more resources into initiatives that reflect real time sensitivity of demand to prices such as improving processes for incorporating dispatchable demand into the pricing and dispatch process.[15]

103. These issues are material for the calculation of benefit-based charges because it avoids (a) overstating the SPD calculation of benefits of a particular asset (b) avoids ascribing a disproportionately high share of benefits to consumers, which has a material effect on the benefit-based charges when half hourly caps are reached and (c) in practice generators may be able to reduce their calculated share of benefits by raising the price of infra-marginal offer tranches (this has the effect of increasing generators costs and reducing their profits under the current benefit calculation method).

104. By our estimation, the proposed benefit calculations would see consumers paying around 65% of benefit-based or SPD charges (compared to 35% directly falling to generators). If the calculation method was amended to include a nominal demand response (price elasticity of demand of say -0.01) this share of charges would fall to 50%. This is without taking account of the ability of generators to act strategically to reduce calculated benefits on inframarginal offers.

105. We tend to the view that the most prudent and efficient approach to benefit calculation and elasticities would be to use long-run demand elasticities (at least where charges apply to assets already in existence). In anticipation of the EA reconsidering its calculation of benefits we have outlined our current thinking on this issue in Appendix A.

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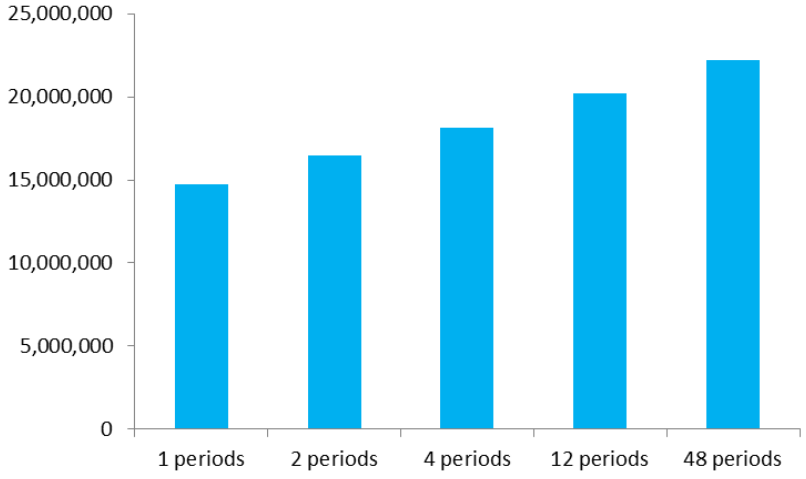
[15] This might also extend to investigating the use of demand-side bidding in the calculation of consumer benefits. Although we appreciate that there are a number of important hurdles to using demand side bids in SPD charge calculations, not least of which is the extent to which these bids can be made binding.

Issue – revenue caps which minimise benefit-based charges

106. In our view the EA also needs to consider adjusting the revenue cap so that more of the cost of transmission is linked to benefits. However this would come with greater opportunity for participants to game the system to reduce their exposure to transmission charges. There is no easy answer here and this is something we believe the EA needs to consider more carefully before finalising its methodology.
107. Lifting the revenue cap from a half hour cap to a daily cap (48 periods) would raise NIGUP annual revenue from SPD charges by 50% ($7.5 million) – see Figure 11. While this is small $ amount relative to the annual required revenue it is an important adjustment. If an asset is not delivering its expected benefits it becomes important to maximise the amount of revenue being recovered from those who are benefitting from the asset.
108. Imposing a short term cap of up to 48 trading periods (a day) would ensure that there are few opportunities for inefficient incentives to avoid benefit based charges, while materially increasing the quantum of revenue collected from benefit-based charges.

Figure 11 NIGUP SPD-based with alternative revenue caps

Indicative average annual SPD based revenue by number of half hour trading periods used to cap revenue

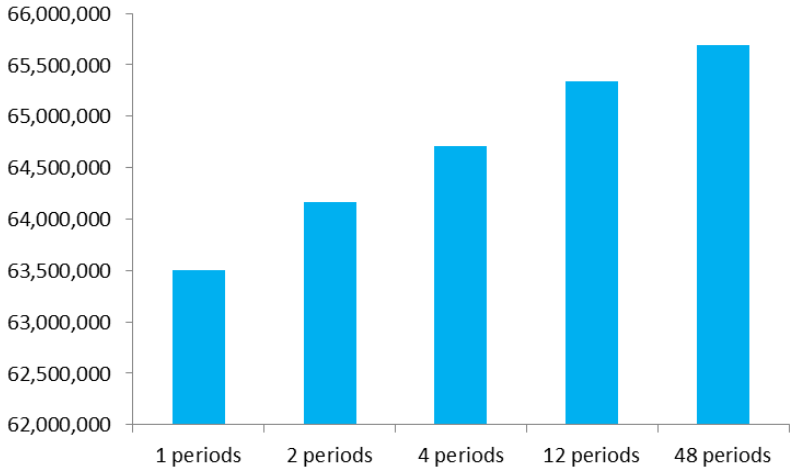


Source: NZIER, EA

109. A revenue cap extended over several periods throughout the day would also have a material effect on the amount Pole 2 revenue recovered through the SPD method – Figure 12.

Figure 12 HVDC SPD-based with alternative revenue caps

Indicative average annual SPD based revenue by number of half hour trading periods used to cap revenue



Source: NZIER, EA

Issue – 2004 cut off and the inclusion of HVDC Pole 2

110. The proposal to include HVDC pole 2 in benefit-based charges seems expedient. Despite this, we do see 3 potential advantages to measuring benefits from the HVDC and charging on that basis.

111. One advantage of including the HVDC pole 2 in benefit based charges is that it could be coupled with Pole 3 for calculation of benefits (both factual and counterfactual solves). We think this makes sense because Poles 2 and 3 are to some extent complements and thus calculating the benefits of these assets collectively is logical. We also note that including both assets in a single (asset in and asset out) solve would ensure a larger and more realistic share of charges HVDC related charges being based on benefits.

112. The other two potential advantages are more uncertain as far as we can tell from evidence to date. One potential advantage is a possible reduction in the likelihood of disputes in the future over who should pay for sunk assets. We are not convinced this will be the case. A second potential advantage is that a benefit based charge could be dynamically more efficient than the status quo in terms of locational price signals for investment. Whether or not this is the case rests on the extent to which existing charges are already embodied in end prices to consumers and thus the extent to which HVDC charges have a real resource cost. In general, benefit based charges will better reflect scarcity of supply and the costs of that scarcity compared with the status quo.

South Island Investment

Consider what occurs when an investor is contemplating locating new load in the South Island. The investor knows that if supply is constrained in the South, southward flow on the HVDC will limit the extent of price increases.

If the cost of the HVDC is embodied in the underlying (e.g. long run marginal) cost of supply and this cost is spread across all consumers then the investor has no incentive or signal at the margin to take account of where they decide to invest, in terms of the cost of the HVDC.

Meanwhile, their decision to locate load in the South Island will raise prices faced by a consumer in the North Island in the event that supply in the South is constrained.

If, however, HVDC charges are based on benefits received from the HVDC then North Island load will see smaller increases in prices as South Island load picks up a higher share of the resource cost of supply. The investor will want to take this into account and decided what the relative risks are of South Island supply constraint and associated costs.

115. The benefit based charge provides an additional and entirely reasonable locational signal to market participants (principally load) about the costs and benefits of investment decisions.
116. It is important to note that the price facing North island consumers is (currently) going to be very high anyway when supply in the South Island is constrained. This raises the stakes in terms of consumer welfare gains from small price reductions. The key is that the benefit based charge insulates those who are not benefitting from the asset from having to pay for the HVDC when prices are high.
117. The existence of benefits from the HVDC is however utterly dependent on there being a real resource cost faced by consumers from the current HVDC HAMI charge. This appears to have been the view of TPAG, which concluded that the HAMI charge reduced South Island generation (including new investment) and raised costs to consumers.
118. We are not convinced that this cost is material (e.g. see our TPAG submission). Our view is that the HAMI charge was long ago factored into the value of the assets of South Island generators. While the HAMI charge may have suppressed investment in generation in the South Island we do not think this effect is especially significant.
119. If it is the case that the current HVDC charge has no (or no material) impact on generation investment and consumer prices then there is no real resource cost and a benefit based charge would simply result in a wealth transfer and no useful additional price signals and no gains in dynamic efficiency.

Issue – RCPD/RCPI

120. The proposal to raise the residual revenue on the basis of RCPD and RCPI needs further consideration. The potential for dynamic efficiency gains in investment decision making hinge to a large extent on the ultimate incidence of these residual charges.
121. If the EA wants to promote improved investment decision making, which we think it should, then it must give careful consideration to constructing the residual charge in a way that minimises the pass through of residual charges to end consumers. This would help to ensure that parties facing these charges have a real incentive to weigh in on decisions that may cause increases in these charges.
122. It is likely that an RCPI charge would be passed through in part or entirely to consumers and so this is unlikely to be a good basis for charging generators for their share of a residual.[16] Indeed we believe the EA should consider charging consumers and generators on different bases.
123. The RCPD method could be useful for signalling the costs that peak load imposes in terms of driving grid investment (assuming that it is implemented with parameters which reflect actual capacity constraints and costs being imposed). Although other capacity based charging methods should not be discounted out of hand.
124. The basis for charging generators could well be an altogether different charging basis. This might include some form of annual lump sum charge more reflective of capacity than peak generation – similar to the current HAMI charge applied to the HVDC. Whatever the case, it should be designed so as to reduce prospects for pass-through.
125. There will of course be trade-offs to consider. We are conscious that if generators cannot pass charges through to consumers in short run pricing then these costs end up in consumer prices over the long run (via changes to investment). The question is whether this kind of pass through is less efficient than more direct and more rapid pass through.
126. It is extremely unlikely that rapid pass through will be more efficient than more prolonged pass through. One reason for this is that as demand grows and new generation investment is needed, there will be a decline in the share of charges being levied through the residual. In the meantime consumers will not face lower charges than they otherwise would which is clearly beneficial to the extent that revenue is being recovered from a broad(er) base.

[16] Especially if coincident peak charge became de facto energy charge because the absence of capacity constraints meant the charge was calculated on 17520 'peaks'

Issue – Producers response

127. There will be some scope for generators to adapt their behaviour to shift interconnection charges onto consumers in the short to medium term.[17] The mechanism for, and magnitude of, any cost shifting will vary depending on the precise design parameters of the RCP charges and the share of revenue collected by the SPD mechanism, which is less amenable to cost shifting compared to the RCPI charge.

RCPI pass-through

128. In the case of the RCPI charges, costs will be passed through by prices being set higher in the wholesale market and through interconnection charges being included in retail and futures contracts. The degree of pass through will depend on the number of peak periods chosen to calculate peaks upon which charges are based: the fewer the number of peaks, the lower the rate of pass through. In the extreme, the RCP charge could be based on an average of 'peaks' over all 17520 half hours during a year (capacity measurement period). This would make the RCPI charge an energy charge which would be factored into all generators' offers. To state the obvious the EA has very important trade-offs to consider here.

Benefit-based charge avoidance

129. There is limited scope for generators to pass SPD benefit-based charges on to consumers through systematically higher prices. The reason we say this is that price setting generators will not face benefit-based charges and thus have limited incentive to raise prices – in response to transmission charges. If they have sufficient ability to impose price increases then this is an issue in and of itself and not a matter peculiar to benefit based interconnection charges.
130. The absence of incentives to raise prices is illustrated in Figure 13.[18] The SPD method importantly assumes that generators offer their production at cost and so the last (price setting) generator in the merit order is deemed not to benefit from interconnection assets. If the generator tries to lift prices to defray transmission charges on its intra-marginal offers, this will lift transmission charges (i.e. benefits) and the price setting generator (in this example a South Island generator) runs the risk that competing generation is dispatched. Recall that in this example the North Island competitor has nothing to lose and no reason to let the South Island generator be dispatched at the higher price.
131. Note also that if the price setting generator does raise the market price during a period where charges have struck the half hourly revenue cap then the

[17] In the longer term all charges will be passed through to consumers by changes to long run investment patterns.

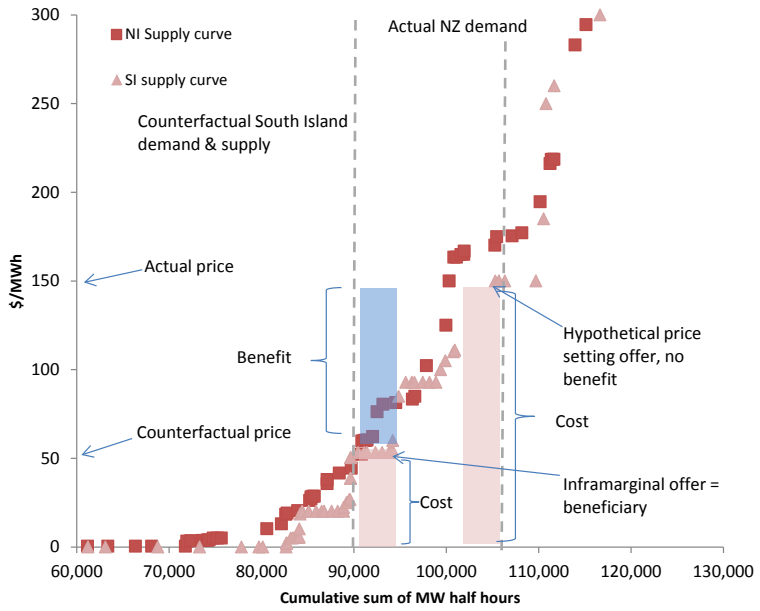
[18] Note that the example here is stylised with North Island and South Island offer curves mapped alongside each other rather than ordered by price and volume irrespective of island of location.

generator will also be reducing the benefits accruing to consumers and will reduce consumers' share of the benefit based charges.

132. This is not to say that it is impossible for firms to game prices in the market. It may even be that there are strategies which would allow firms to pass through costs. However, these are not obvious and are unlikely to be sustainable.

Figure 13 No marginal incentive to raise prices

Stylised example of HVDC pole 2 SPD charge calculation



Source: NZIER

133. Generators will, however, try to minimise the calculation of their benefits by raising offer prices in ways that increase estimated costs to generators or raise estimated benefits to consumers.

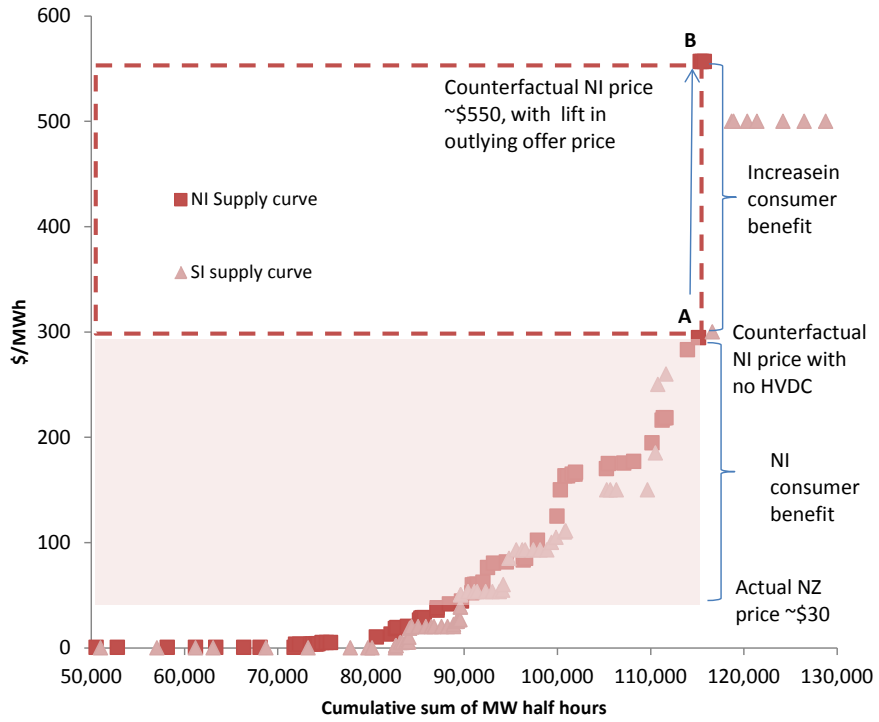
134. The capacity to increase estimated costs can be seen in Figure 13 where the intra-marginal offer, which benefits from higher prices, could be offered at a higher price and will still be dispatched. A higher offer would be assumed to be higher costs and the generator's benefit would fall accordingly. There is a reasonably wide scope for generators to lift their offers to raise their 'implied' costs because at the present time the vast majority of generation is offered at ~$0.

135. There is also potential for producers to attempt to increase consumers' benefits by raising offers that would only be considered under the counterfactual part of the benefit calculation. This is shown in figure 14 where the price setting generator in the 'no HVDC' counterfactual lifts the offer price from A to B.

136. The raising of offers, or 'hockey-sticking', is likely to be an issue regardless of whether generators change their offer behaviour. This is because generator offers already have this general hockey-stick shape due to what appears to be systematic attempts by generators to achieve extremely high prices in the event of disruption to the grid or other anomalous events. Appropriate calculation of consumer benefits, including demand response, will help limit the effect of this behaviour on consumers.

Figure 14 Lift in outlying offers – increased consumer benefit

Stylised example based on HVDC benefit calculation



Source: NZIER

137. Our views on generator offer behaviour and judgement that SPD charges are not likely to be passed through (although they will be avoided somewhat) is supported by supply function equilibrium modelling which shows that a tax on 'observed' profits (akin to the SPD method), in effect leads to increased competition over the last spot(s) in the merit order - a sweet spot where no taxes or charges are imposed (at the margin).[19] Generators can be expected to raise low priced offer tranches to reduce observed profits. However, in terms of spot market prices the net effect is likely to be lower market clearing prices

[19] See Philpot, A. (2012) 'Taxation and supply-function equilibrium' available at http://www.epoc.org.nz/papers/TaxationAndSFEv16.pdf.

as competition over prices in the region where the market clears becomes more intense, in equilibrium.

3.4. Can the proposal deliver a net benefit

138. In summary, and without attempting to develop a quantitative estimate of net economic benefits, we have attempted to assemble our analysis of the intended and unintended outcomes in the following table. This table is more of a 'one page' view of our work. Our ultimate assessment is set out in section 4.

Table 3 TPM proposal – outcomes

	Who benefits	What benefit	Value	Probability of outcome	So what
Intended Outcomes					
Efficient future grid investments	Gen + load	cost saving = skin in game	low	depends on grid use [outlook = flat demand, low capex]	Limited short term importance
Minimise free riding	Some load	Efficient pricing	low	Unlikely to eliminate avoidance of grid charges	redesign needed
Reduced lobbying	everyone	cost saving	low	Disputes will persist	Small gain?
Beneficiary pays	Gen + load	economic costs/pricing	low	Depends on details of SPD method	Improvement
Other Outcomes					
Identify value of sunk assets	NZ Inc	Dynamic gains	med	Depends on SPD structure	Likely material
Pass-through by generators	Generators	profit	med	Consumers will pay in long run	inevitable
Demand side do respond	Some load	Likely none	low	Demand will do what they see as best	Likely inefficient
Increase capping period	everyone	Identify more beneficiaries	high	Very tricky to avoid downsides from increase	Risky

4. NZIER assessment

4.1. Overall thoughts

139. The proposed 'beneficiary pays' approach seeks to address two very different economic problems:

- the first is how to raise revenues to pay for sunk assets in the least distortionary way;
- the second is to address a currently under-priced free riding problem whereby the actions of grid customers affect subsequent transmission investment costs that are then socialised to the whole market.

140. We are comfortable that the proposed 'beneficiary pays' approach could address the second issue to the extent that benefits can be identified. This would relate to grid projects that are some years away before being committed because load and generation may invest differently and change the need for the grid upgrades. We could expect that initiatives by grid customers will sufficiently account for the effects they cause to the timing and cost of grid investment because they can expect to pay incrementally more and/or sooner for the upgrade they induce.

141. In our Section 3 analysis we have discussed what we originally viewed as 'wrinkles' in the EA proposal but that came to represent, for us, significant potential for unintended outcomes as we worked further through analysing the proposal. Our views on these issues were set out in the section 3 analysis and are not repeated here. Our major concerns are as follows.

4.2. No demand response

142. The ability of producers to artificially raise consumer benefits points to one of the most important problems with the EA's proposal: the absence of demand response from the calculation of consumer benefits.

143. The SPD method suggests the benefit of HVDC pole 2 in 2011 was in the order of $13,500,000,000 or $770,000 per half hour. Of this benefit, around 95% accrues to consumers ($12,800,000,000). Counting all of this value as a 'benefit' assumes that consumers would not change their behaviour if prices increased from $55 average of 2011 to approximately $400.[20] This is clearly not true. Major consumers, for example, would begin to curtail production if they saw these kinds of prices on the horizon.

[20] For many consumers the benefit which is calculated implies no behaviour change at orders of magnitude somewhat larger than this. For example, demand at Penrose is assumed not to respond when prices are, on average, $590/MWh.

144. In some cases the counterfactual assumption of no demand change beggars belief. The benefit a consumer in the North Island is calculated to have received from the HVDC on May 30 2011 assumes no change in demand with prices at $1,030/MWh as compared to $30/MWh. This may be a fair assumption for the short term and for some kinds of loads. However, it is genuinely silly for major users. If they know that the price is heading to $1,000 they will shut down or, for those who can, ramp up their own generation and dispatch to the grid – i.e. their behaviour changes considerably to the point where they may even become a net supplier to the grid.
145. It is also quite possible that all forms of demand will become more responsive in the future – either through residential real-time metering and related improvements in information systems or advances in dispatchable demand.

- One option for incorporating demand response is to use wholesale market bids however this approach would not currently work. Bids are not binding and they would therefore be open to considerable manipulation - much as outlying offers are not binding (in practice) and are equally open to manipulation.

146. In essence, the SPD method needs a way of: (a) characterizing demand into elastic and inelastic and (b) parameterizing demand response for those demands that are elastic (c) adjusting calculations to account for the rather tricky problem of nodes which change sign.

- This would be a significant improvement in the methodology and would help to address some of the benefit shifting issues associated with e.g. 'hockey-sticking'.
- Introducing assumptions about demand response would have the unfortunate consequence of introducing debate over the magnitude of such response. This would open up the pricing methodology to on-going debate. This is unavoidable though, because without such a mechanism the benefit calculations will stretch credibility, the method itself will not have much in the way of legitimacy, and thus the pricing methodology would not be very durable.

4.3. Embedded generation

147. It is not clear what is envisioned for embedded generation. The EA must carefully consider and clarify the treatment of embedded generation in the proposed TPM. This includes clarifying how a node which is the site of injection and off take will be classified for the purposes of regional coincident peak ('residual') charges.
148. To support consideration of embedded generation we suggest that any and all charges must relate to net injection or off take at the point of connection to

the grid. This is the best basis upon which to measure the benefits of interconnection.

149. The EA appears to suggest, in places, that embedded generation could be charged on the basis of gross output. This would be a strange state of affairs that would not be consistent with the beneficiary pays principle or dynamic efficiency. When generators choose to embed this demonstrates that they do not (or cannot) derive sufficient benefit from the interconnected grid to make it worthwhile connecting - even in the absence (currently) of interconnection charges. The same can also be said for the load which some embedded generators are entirely dependent upon (as in the case of some cogeneration). The only benefit embedded generation derives is in relation to the net exchange that occurs at the point of connection to the grid.

150. The EA has correctly identified that problems could arise for embedded generation from inefficient pass through of charges by distributors (e.g. if benefit based charges are being passed to generators whose generation has been displaced). However this should be dealt with in the context of the regulation of distribution charges and not in the setting of the transmission pricing methodology.

4.4. Is there a dynamic flaw

151. Our analysis in Section 3.2.1 of the benefits of the proposed TPM versus the status quo highlighted the triviality of allocative efficiency gains relative to dynamic gains. In a regulatory regime where the transmission owner is guaranteed a return on investment, the costs to consumers of regulatory bodies getting it 'wrong' can be immense dynamic inefficiencies. Currently, it appears, there is no mechanism for reducing the likelihood of this outcome.

152. The key questions to be answered in our view are:

- will the industry at large benefit from a TPM which, via the SPD method, shines a light on;
  - the vast benefits that many grumble about paying for (free-rider problems)
  - the true magnitude of costly mistakes and the inefficiency of passing those costs to precisely those who should be encouraged, not discouraged from using these sunk assets (a dynamic flaw in the regulatory architecture)
- will the proposed TPM reduce the likelihood that;
  - people lobby against valuable projects because they believe they will carry the cost while others benefit
  - consumers will be left carrying the cost of mistakes again in the future.

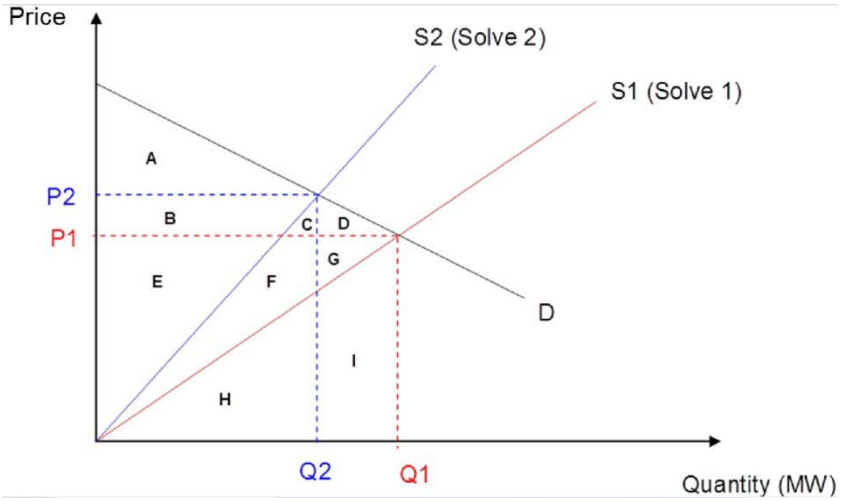
153. We are broadly on the same page as the EA in believing that the benefits of their proposal lie very much in the answers to these questions. We do not, however, think that they have adequately answered them and we do worry about what else would change. By this we mean that transmission investments are developed, decided upon and implemented by an administrative system that needs to be fully in sync if it is to have any hope of producing a market like outcome.

Appendix A Elasticities & calculation of consumer benefits

154. While the discussion below may be seen as a distraction in the context of the submission process we nevertheless see it as a matter that has importance to the significant flaw in the EA TPM proposal as well as a policy matter outside of the consultation process.

155. The method proposed by the EA to measure benefits to electricity consumers, illustrated in Section 3, is a conventional method in welfare economics textbooks. However that conventional framework for estimating benefits from consumer surplus changes makes little to no distinction between long-run and short-run demand schedules. We would expect that long-run demand elasticities are larger than short-run, encompassing notions of grid users adapting and innovating around the provision of infrastructure facilities over time. That is, the long-term demand schedule would be flatter.

Figure 15 EA's illustration of calculating benefits



Source: EA Consultation Paper, 10 October 2012, page 91

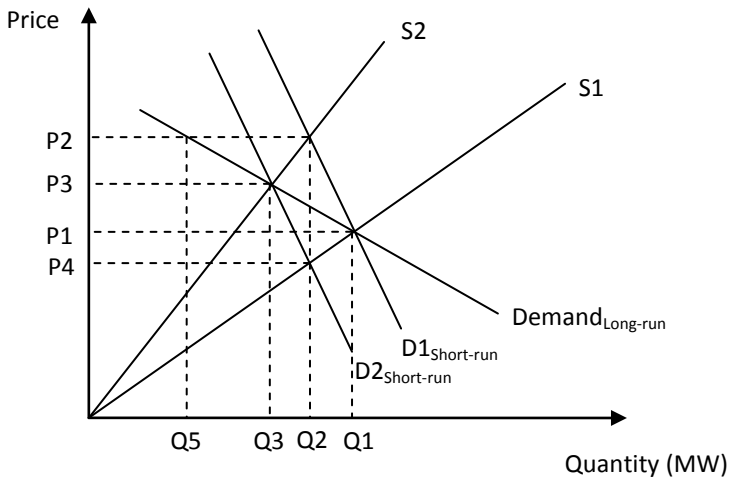
156. A more elastic long-run demand means multiple short-run demand schedules. The short-run demand schedule that the EA has drawn in and proposes to use would lie to the right of what it would have been had the transmission asset in question never existed. This is illustrated in Figure 16 where $D1_{Short\text{-}run}$ is the 'factual' short-run demand, and $D2_{Short\text{-}run}$ is the 'counterfactual' whereby the transmission asset had never historically been built.

157. To assess benefits from the 'factual' short-run demand actually observed may overestimate the benefits, because grid customers may have become more dependent on the grid than they would have been. Charging on the basis of short-run benefits may cause grid customers to substitute away from grid-dependence (say by progressively shutting down grid-dependent technologies, or investing in their own electricity generation).

158. Consider a simplified example for instance[21], whereby the grid asset never was, and price and quantity are P3 and Q3 respectively in Figure 16. Building the grid asset lowers prices to P4, but a beneficiaries pays charge is introduced such that existing consumers still face P3, and only new consumers get prices progressively lower to P4. This might occur if the project was built just at the moment that it broke even in economic terms, and people are indifferent between the project existing or not. However, in the absence of a benefit-pays approach, as has historically been the case, all consumers face price P4. Say that people adapt in the long-run to become more dependent on the asset, shifting short-run demand until it is positioned at its new long-run equilibrium at price P1 and quantity Q1 in Figure 16 (labelled to match the EA's above).

159. Then a beneficiaries-pays approach is levied, raising prices to P2. But P2 exceeds what it would have been if the project had never been built — contrary to what is assumed in the EA's proposed approach. The effect would be to price some grid users out of the market over time, close down aspects of people's businesses, until eventually the short -run demand schedule went back to D2

Figure 16 Long-run demand and a multitude of short-run demands



Source: NZIER

[21] Assume that there is no underlying growth, so that the demand schedules drawn would remain static; that increases in quantity demanded relate to new customers rather than existing customers using more; and that in the business as usual TPM the revenue requirement is spread so thinly and widely that they don't significantly change the prices described here.

160. This is an illustration of dynamic efficiency. In this case the late levying of an unanticipated beneficiaries-pays approach could cause the loss of social surplus between the two demand schedules D1 and D2 and above S1. (However, this isn't a loss of 'manna from heaven', as the implicit subsidy that attracted customers to invest in the asset's neighbourhood would have suppressed economic development by others elsewhere to a similar level.)
161. This also raises a question of how a beneficiaries approach should best be levied: should short- or long-run elasticities be used? Either way, price will be P3 in the long-run, but it is a question of how quickly, and with how much collateral damage. Short-run elasticities would shoot the price up to P2, causing various customers to evacuate quickly and moving the $D1_{Short\text{-}term}$ curve quickly leftwards, possibly overshooting $D2_{Short\text{-}term}$. The advantage is that more money is quickly raised that reduces the size of the residual revenue requirement. As well as risking overshooting the mark, a quicker transition means the possible redundancy of specific assets of grid customers that still have an economic life.
162. There is also an issue of fairness and equity that the losers could argue on efficiency grounds, given they would be suffering because of the changing positions of the administrative system. Those stakeholders are free to argue that their losses be weighted more highly than gains to others in the efficiency assessment; after all, the Kaldor-Hicks criterion of weighting all stakeholders with standing equally is a criteria used because of its expedience[22].
163. We would suggest that a more prudent approach would be to use long-run demand elasticities for the beneficiaries-pays procedure as it applies to sunk assets already in existence. This would correspond to a price increase to P3 rather than P2. This would produce a less risky and relatively fairer transition to a long-run equilibrium, with potential added efficiency by better supporting continued use of customers' assets that would otherwise have no opportunity cost. In the long-run when all the adjustments have been made, then short-run elasticities could be used.
164. For future grid investments a short-run elasticity could apply, as existing customers would continue to face price P3, and the demand curve would not materially shift (because nobody would be materially net-better off because of the grid investment).

[22] Whereby 'a policy should be adopted if and only if those who will gain *could* fully compensate those who will lose and still be better off', which provides the basis for the *potential Pareto rule*. It means as long as net benefits are positive it is at least possible in theory that losers could be compensated so that the policy potentially could be Pareto improving. Boardman et al 2006, p31.