Appendix D Assessment of materiality of problems with interconnection charges under the current TPM

D1. Introduction

D1.1 Purpose of this Appendix

1 This Appendix assesses the efficiency of current interconnection charging arrangements. It feeds into the problem definition section in Chapter 4 of the issues paper, which discusses the nature and materiality of problems with the current TPM.

2 The Appendix begins by assessing the inefficiency of failing to recover interconnection costs from the beneficiaries of interconnection investments (Section D2). In particular, it considers costs and benefits of removing the RCPD charge entirely and recovering interconnection costs through some notional beneficiaries pay method.

3 The assessment considers that applying beneficiaries pay to interconnection costs could drive more efficient investment through:

a. improved transmission investment decision making; or

b. more efficient generation and demand-side investment; or

c. both a and b.

4 The current interconnection charge results in inefficient outcomes, to the extent that it fails to capture these benefits.

5 Beneficiaries-pay approaches are used as a point of reference because they are the next tier up from “alternative charging options” (e.g. the current interconnection charge) in the economic framework. The analysis in this Appendix does not rule out the possibility that other tiers of the framework (i.e. exacerbators-pay or market-based approaches) could also deliver benefit.

6 The Appendix concludes with an assessment of the effects of the current interconnection charge on electricity market investment and operation (Section D3).

7 The assessment considers the effects of the RCPD allocation of interconnection charges, through incentivising demand reductions and operation of embedded generation in regional peak periods.

8 It is important to emphasise that this Appendix is not a cost-benefit analysis:

a. it does not describe alternatives to the status quo (in particular, it does not discuss *how* beneficiaries pay could be applied to allocate charges);

b. it does not consider the costs of implementing alternatives; and

c. it does not consider issues such as acceptability or providing certainty to investors.

Rather, the Appendix identifies problems that are candidates for resolution through the review and amendment of the TPM.

9 Further, the methodology applied is quite different from the methodology used for the cost-benefit analysis of the Authority’s proposal for the TPM set out in Appendix F. Accordingly, the estimates in this Appendix are only comparable to the Appendix F cost-benefit analysis in terms of the general level of costs and benefits rather than the specific and overall values.

10 This Appendix is broadly equivalent to Appendix C (which assesses the efficiency of current HVDC charging arrangements). One key difference is that Appendix C includes an assessment of the extent to which the HVDC charge is consistent with beneficiaries pay. No such assessment is needed here; it is clear that the interconnection charge is not consistent with beneficiaries pay. The parties that derive a private benefit from the interconnected grid either do not pay the interconnection charge, or do not pay a charge commensurate with their private benefit. In particular:

a. generators can benefit from interconnection, but do not pay interconnection charges (except to the extent that they draw power from the grid);

b. retailers can benefit from interconnection, but do not directly pay interconnection charges;

c. consumers do pay interconnection charges (directly or indirectly) – but the charge paid by a particular consumer is not driven by the private benefit that the consumer derives from the interconnected grid; and

d. distributors pay interconnection charges, but the charges do not relate to the benefit distributors derive from the transmission grid, such as access to the wholesale electricity market to offer interruptible load.

11 All costs and benefits in this Appendix are expressed on a pre-tax basis. A real discount rate of 6% (pre-tax) is used throughout.

D1.2 Key findings

12 The total cost of major investments in the interconnected grid over the next 20 years is estimated to be at least $725M PV. (This excludes connection investments, NRS, HVDC investments, small investments under $20M, like-for-like replacements, and investments that are already approved or in the approval process.)

13 In some cases, applying beneficiaries pay could defer or avoid such transmission investment (where it is efficient to do so), resulting in a national net benefit.

14 There is considerable uncertainty about the scale of the potential benefit of applying beneficiaries pay to interconnection costs. In order to put bounds on the potential value of applying beneficiaries pay, three scenarios are considered – A (low net benefit), B (medium net benefit) and C (high net benefit). The key assumptions for these scenarios are set out in paragraph 32. The analysis suggests that the net benefit lies in the range of $12-170M NPV, with point estimate of $67M. Estimated net benefits are summarised in the table below (as pre-tax 2012 NPV).

Source of benefit	**National benefit – low scenario (“A”)**	**Medium scenario (“B”)**	**High scenario (“C”)**
Improved transmission investment decision-making	$0	$22M	$72M
Changes to generation and demand-side investment and operation, to defer import-driven transmission investment where it is efficient to do so	$0	$20M	$48M
Changes to generation investment, to defer export-driven transmission investment where it is efficient to do so	$12M	$25M	$50M
Total	**$12M**	**$67M**	**$170M**

15 The current interconnection charge results in inefficient outcomes, to the extent that it fails to capture these benefits. To some extent they can be realised through RCPD signalling, nodal pricing and/or the Commerce Commission’s transmission alternatives regime, but not in all cases.

16 The assessment of the effects of the interconnection charge on market investment and operation identifies that current arrangements are expected to result in:

a. a net cost on the order of $5M (NPV) through incentivising major LNI consumers to shift demand out of RCPD periods;

b. a deadweight loss on the order of $30M (PV) through incentivising mass-market consumers to inefficiently reduce demand;

c. possible net benefits in the millions of dollars (NPV) in the short to medium term, to the extent that they incentivise an efficient combination of transmission, generation and demand in the UNI (and perhaps also the USI); and

d. potentially substantially higher net benefits, to the extent that they incentivise an efficient combination of transmission, generation and demand in the longer term (though there is also a risk that the incentive will become excessively strong and result in outcomes such as an inefficiently high level of embedded generation in the UNI and USI).

D2. Inefficiency stemming from failing to recover interconnection costs from beneficiaries

17 The following sections assess the efficiency gains that could stem from applying beneficiaries pay to the interconnected grid. Regulatory arrangements including nodal pricing, the RCPD allocation of transmission charges, and the Commerce Commission's transmission alternatives regime, can all support efficient investment – but all have their limitations.

18 Section D2.1 discusses the need for major transmission investments in New Zealand over the next 20 years – which is a key driver of the analysis.

19 The Appendix proceeds to assess potential efficiency gains through:

a. improved transmission investment decision making (Section D2.2); and

b. more efficient generation and demand-side investment (Section D2.3).

D2.1 Interconnected grid investment needs

20 The table on page 7 lists potential major interconnected grid investments, excluding:

a. investment in connection assets, NRS assets and HVDC assets;

b. investments expected to cost less than $20M in real terms (which are numerous but are expected to contribute a relatively small proportion of total costs);

c. investments that are unlikely to occur in the next 20 years;

d. condition-based like-for-like replacements; and

e. investments that are already approved or in the approval process.

21 Most of the data in the table comes from Transpower's Annual Planning Report 2012[1] or other public sources. The last three columns, however, include some figures that are merely assumptions made by the Authority (because public sources are not available).

22 The Authority appreciates that it is impossible to foresee all investment needs 20 years in advance. The transmission investment programme must change over time, in response to circumstances. The intention is only to summarise the current state of knowledge.

23 All costs and timelines in the table are approximate. All potential transmission solutions are indicative and may change as a result of considering other options and determining the most appropriate solution.

24 Projects have been divided into four categories because it is convenient for the structure of this Appendix. These are:

a. reinforcement into (and through) the upper North Island;

b. investments to increase reliability in other regions (by increasing import capacity)

c. investments to enable new generation; and

d. investments to enable specific new loads.

25 Among investments that have already been approved:

a. the North Island Grid Upgrade (NIGU)[2] and North Auckland and Northland upgrade (NAaN)[3] fall into the first category;

[1] http://www.transpower.co.nz/annual-planning-report-2012

b. the Lower South Island Reliability project[4] falls into the second category;

c. the Lower South Island Renewables project[5] falls primarily into the third category – as to some extent does the Wairakei Ring project[6], although the latter also serves to increase transmission capacity into Auckland; and

d. the Dobson-Reefton upgrade[7] could perhaps be said to fall into the fourth category, since it was driven in large part by the expectation of demand increases for a relatively small number of end consumers (mainly in the mining and dairy industries).

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2 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/

3 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/

4 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/

5 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/

6 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/

7 http://www.ea.govt.nz/industry/ec-archive/grid-investment-archive/gup/2007-gup/west-coast-upgrade-plan/

Category	Indicative potential investment	Page of 2012 APR	Potential need date	Indicative cost (real $M)	For PV calculations: Assumed year	Assumed cost (real $M)	Indicative PV of costs (2012 $M, pre-tax, using 6% real DR)
Upper North Island reinforcement	Second Penrose-Albany cable	87	Beyond 15 years	Order of $100M (based on NAaN GUP)	2027	100	42
	Additional circuits between Pakuranga, Penrose and Mt Roskill	110, 122	Long term	Order of $100-150M (based on NAaN GUP)	2027	125	52
	Additional circuits between Otahuhu and Brownhill	110	Long term	Order of $100-150M (based on NIGU GUP)	2027	125	52
	Additional capacity from Otahuhu to Wiri	121	?	$20-50M	2022	30	17
	Enabling operation of the NIGU at its construction voltage of 400 kV	51	Beyond 15 years	Order of $200M (based on NIGU GUP)	2027	200	83
Reinforcement into other regions	Wairakei to Atiamuri reconductoring or new circuit(s), to support the Bay of Plenty	54	Long term	?	2027	30	13
	Various upgrades in Tauranga / Te Matai area	151	In 10-20 years	?	2027	30	13
	New transmission from the Waitaki Valley to support the Upper South Island	70	From USI Major Capex Proposal - late 2020s or 2030s	From USI Major Capex Proposal - indicatively $0.5B	2030	500	175
	Thermal upgrade of Benmore-Twizel, to support high south flows in dry years	73	Not in short term	?	2027	30	13
	Thermal upgrades around Invercargill / North Makarewa / Three Mile Hill	75	Late in the forecast period	?	2027	30	13
Enabling generation	Increased export capacity from Hawkes Bay	205	Driven by "large increase in new gen."	?	2025	100	47
	Increased export capacity from Taranaki	57	Substantial new generation in region	?			
	Reconductoring of Tokaanu-Whakamaru and Bunnythorpe-Tangiwai-Rangipo, possibly followed by further capacity increases over Bunnythorpe-Whakamaru	59	Substantial new generation at or south of Bunnythorpe	Tranche 1 is $100-300M, tranche 2 could be a lot more	2020	200	125
	Reconductoring (or converting to 220 kV) circuits around Bunnythorpe / Linton / Woodville	62, 180	Substantial new wind generation in region	?	2020	30	19
	New 220 kV line from the Wairarapa to Bunnythorpe/Linton	62	When required to connect new wind	?	2020	100	63
Enabling specific loads	Additional capacity from Livingston to Oamaru	284	Short to medium term	?			

(Assumptions made by the Authority for the purpose of this work are highlighted in red. Other assumptions come from the 2012 APR except where noted otherwise.)

D2.2 Potential benefits from incentivising beneficiaries to participate in transmission investment decision making

26 This section assesses the potential scale of benefits that may be obtained through improving decision making processes with regard to transmission investment – by incentivising beneficiaries to:

a. discover and promote better transmission investment options; or

b. seek deferral or cancellation of transmission investment where it is efficient to do so; or

c. both a and b.

27 This section does not consider benefits that may be obtained by changing generation or demand-side investment so as to reduce the need for transmission investment – such benefits are covered in Section D2.3.

28 Based on the table on the previous page, the total cost of major investments in the interconnected grid over the next 20 years is estimated at $725M PV. (This excludes connection investments, NRS, HVDC investments, small investments under $20M, like-for-like replacements, and investments that are already approved or in the approval process.)

29 In fact the true cost may be higher, since some transmission needs that will occur in the next 20 years may not have been anticipated yet, but for this purpose it is conservatively assumed that $725M is correct.

30 It may be possible to reduce this cost through improved decision making processes.

31 In order to put bounds on the potential benefit, three scenarios are proposed:

a. in which current decision-making processes are as good as can be reasonably expected given the information available, and **no improvement** can be achieved by changing the way in which interconnected grid costs are recovered;

b. in which it is possible to achieve a **3% reduction in transmission costs** (with no increase in costs elsewhere) through more targeted cost recovery, by:

- deferring 10% of investments by two years; and
- finding better transmission solutions that allow transmission costs to be reduced by 15% for 10% of investments;

c. in which it is possible to achieve a **10% reduction in transmission costs** (with no increase in costs elsewhere) through more targeted cost recovery, by:

- deferring 20% of investments by two years;
- finding better transmission solutions that allow transmission costs to be reduced by 10% for 20% of investments; and
- avoiding 5% of investments entirely.

32 Scenario b provides a benefit of $22M PV, and scenario c provides a benefit of $72M PV.

D2.3 Potential benefits from incentivising an efficient combination of investment

33 This section assesses the potential scale of benefits that may be obtained through incentivising an efficient combination of transmission investment, generation and demand-side measures.

34 Benefits that may be obtained purely by making better transmission investment decisions, with no changes to generation or demand-side investment, are not considered here – such benefits are covered in the previous section (D2.2).

35 Recovering the costs of new investment in accordance with beneficiaries pay has the potential to achieve an overall reduction in system costs by:

a. deferring or reducing the need for transmission investment that increases *import* capacity into a potentially import-constrained region *(where it is efficient to do so)*, by:

- incentivising peak-time (or, for that matter, round-the-clock) demand reductions in the region;
- disincentivising major new loads that would increase the need for import capacity from locating in the region; and
- incentivising investment in, and peak-time operation of, generation in the region; and

b. deferring or reducing the need for transmission investment that increases *export* capacity out of a potentially export-constrained region *(where it is efficient to do so)*, by incentivising generators to locate new plant elsewhere.

36 The scale of the potential benefit is driven by the cost of transmission investment that may be required. The table on page 7 identifies:

a. about $250M (PV) of investment to support reliability by increasing capacity into (and through) the upper North Island;

b. about $225M (PV) of investment to support reliability by increasing capacity into other regions; and

c. about $250M (PV) of investment to enable new generation (by increasing export capacity out of the relevant regions).

37 This excludes connection, NRS and HVDC investments, small investments under $20M, like-for-like replacements, and investments that are already approved or in the approval process.

D2.3.1 Import-driven transmission investment

38 This subsection addresses investment to support reliability by providing import capacity, with total estimated cost on the order of $475M (PV).

39 The table on the next page lists ways in which the need for (and hence the cost of) import-driven transmission investment can be reduced, and indicates the extent to which these measures may already occur under the status quo. Measures relating to reactive support are excluded.

Sector	Means of reducing or deferring the need for import-driven investment	Extent to which this may occur under status quo transmission pricing arrangements
Demand-side	Peak-time demand reductions by direct-connect consumers	Incentivised by RCPD *(but some direct-connect consumers do not appear to respond to RCPD signals, and RCPD does not provide an accurate temporal or spatial signal)* May be incentivised by high nodal prices at times of local capacity scarcity *(but generally transmission investments are approved before there is much actual scarcity, on the basis of forward projections of supply and demand)* May be purchased by Transpower as a transmission alternative *(though the Authority is not aware that this has happened to date)*
	Mass-market load control at peak time *(we include this under the 'demand-side' heading because, while it may be controlled by distributors or retailers, it fundamentally stems from consumers)*	Incentivised by RCPD *(but most distributors do not appear to respond to RCPD signals, and RCPD does not provide an accurate temporal or spatial signal)* May be incentivised by high nodal prices *(but often transmission investments are approved before high prices become frequent, and anyway most load control is not available to respond to energy prices because it is being used for higher value uses)* May be purchased by Transpower as a transmission alternative *(though this has not often happened to date)*
	Anytime load reduction (e.g. through electricity efficiency or conservation or both)	Incentivised by energy charges (including RCPD signals, to the extent that these are passed on to end consumers in a variabilised form) May be purchased by Transpower as a transmission alternative *(though the Authority is not aware that this has happened to date)*
Generation	Construct new generation, retain existing generation	RCPD provides a locational signal that may encourage new embedded *peaking* generation to locate in the UNI or USI rather than the LNI or LSI *(if fuel supply permits)* Incentivised by nodal prices – mean prices are typically higher in importing regions May be purchased by Transpower as a transmission alternative *(though the Authority is not aware that this has happened to date)*
	Operate generation at peak time	Incentivised by RCPD, for embedded generation *(but the incentive is relatively weak in the LNI and LSI, and even in the UNI and USI, RCPD does not provide an accurate temporal or spatial signal)* May be incentivised by high nodal prices *(but often transmission investments are approved before high prices become frequent)* May be purchased by Transpower as a transmission alternative *(though this has not often happened to date)*

40 In summary, there are various supply- and demand-side measures that can be used to reduce or defer the need for import-driven transmission investment, but current arrangements may not always provide an efficient price signal to support such outcomes.

41 The Authority is not in a position to carry out detailed cost-benefit analyses of the potential to defer individual investments, since most of the relevant investments are at least 15 years away and the need for them is not yet well understood, and the extent to which current arrangements will deliver efficient outcomes is not clear.

42 In order to put bounds on the potential benefit, three scenarios are proposed:

A. in which current arrangements are sufficient to achieve broadly efficient generation and demand-side investment and operation, and **no improvement** can be achieved by changing the way in which interconnected grid costs are recovered;

B. in which increased targeting of interconnected grid costs:

- leads to more active peak demand management in the upper North Island, sufficient to **defer all listed upper North Island reinforcement by three years**, though with half the deferral benefit being offset by the costs of demand-side response; but
- does not deliver substantial benefit in the upper South Island (where current arrangements already deliver extensive load control) or in the other regions (where the combined PV of potential transmission investments is relatively small anyway);

C. in which increased targeting of interconnected grid costs:

- leads to installation of substantial peaking or mid-merit generation in the upper North Island, or both, (which would not have been delivered by existing arrangements), sufficient to **defer all listed upper North Island reinforcement by three years**, though with half the deferral benefit being offset by (i) the incremental cost of siting the generation in Auckland and (ii) the variable cost of operating the generation at peak times; and
- also leads to construction of additional small- to mid-size hydro generation in the upper South Island (which would not have been delivered by existing arrangements), sufficient to **defer the new line from the Waitaki Valley to Christchurch by three years**, at minimal incremental cost.

43 Given these scenarios and the estimated costs of transmission upgrades, it is straightforward to calculate the expected net benefit as $20M NPV under Scenario B or $48M NPV under Scenario C. These benefits are additional to those set out in Section D2.2.

D2.3.2 Export-driven transmission investment

44 This subsection addresses investment to enable new generation by providing export capacity, with total estimated cost on the order of $250M (2012 PV).

45 Based on the table on page 7, the key role of such investment appears to be to enable:

a. lower cost wind generation in various locations *(for instance, the Manawatu or Wairarapa)*;

b. new South Island hydro generation; and

c. additional gas-fired generation, in the event of a major gas find.

46 For the present the possibility of a major gas find is discounted (though there is a real possibility that such a find will occur at some future point, given the scale of petrochemical exploration). The focus, then, is on the role of the interconnected grid in supporting an efficient combination of new wind, hydro and geothermal generation.

47 The potential benefit of recovering the costs of a particular transmission investment in a more targeted way depend on the economics of the generation enabled by the transmission investment. Three cases are considered, which span a reasonable range of possibilities:

1. in which the resources enabled by the transmission investment are so much superior to the resources in other regions, that the generation developer(s) would be willing to proceed on their original timetable even if they had to bear the full cost of the transmission investment. In this case, a more targeted allocation of transmission costs would not have any impact on investment decisions;

2. in which the resources enabled by the transmission investment are somewhat superior to those available in other regions, so that if the generation developer(s) had to bear the full cost of the transmission investment, they would still proceed with their projects in the area – but deferred by (say) five years. This would allow a five year deferral of the transmission investment – but part of the deferral benefit (say, half) would be offset by the higher cost of developing generation in other regions in the meantime; and

3. in which the resources enabled by the transmission investment are no better than those available in other regions, so that if the generation developer(s) had to bear the full cost of the transmission investment, they would not proceed with projects in the region until opportunities of similar merit in other regions were exhausted (say, ten years). This would allow a ten year deferral of the transmission investment, with no significant offsetting cost.

48 The Wairakei Ring upgrade is probably a good example of case 1; the Lower South Island Renewables upgrade may, with hindsight, be more similar to case 3.

49 It might be suggested that in case 3, the transmission investment would not proceed under status quo arrangements, because the transmission investment approval process is intended to result in optimal investment, and it is not optimal to spend money on enabling new generation in a region when equally good generation opportunities are already available in other regions. However, the current transmission investment regime may in fact allow such investments. If Transpower anticipates that new generation is likely to occur in an export-constrained region, then (regardless of the merits of such generation) it will likely determine that it is economic to increase export capacity from the region, to prevent the new generation becoming an expensive stranded asset. Under current transmission pricing arrangements, there is no

incentive on individual generation investors to correct the impression that they are likely to build in the export-constrained region (even if they know they are actually more likely to site elsewhere).

50 The Authority is not in a position to identify whether each of the potential transmission investments listed in the APR is most similar to case 1 *(in which case there is little benefit to be had, at least in terms of transmission investment, from more targeted cost recovery)*, case 2, or case 3 *(in which case there is potentially a large benefit)*.

51 Three scenarios are therefore put forward:

	Percentage of investment to enable new generation by providing export capacity, by PV:			
Scenario	**Case 1**	**Case 2**	**Case 3**	**Net saving (i.e. transmission deferral benefit minus increase in generation costs), expressed as % of the total PV of such transmission investment**
A (low benefit)	67%	33%	0%	5%
B (medium benefit)	57%	33%	10%	10%
C (high benefit)	13%	67%	20%	20%

52 In Scenario B, for instance, it is assumed that more targeted recovery of transmission costs can allow:

a. 10% of export-driven investment (by PV) to be deferred for 10 years with no offsetting generation-sector cost; and

b. 33% of export-driven investment (by PV) to be deferred for 5 years, though with half of the deferral benefit offset by increased generation-sector costs.

53 In terms of physical assets, this might be achieved by deferring wind and hydro projects in potentially export-constrained areas, at least until more easily accessible resources in other areas had been developed.

54 Given these scenarios and the estimated costs of transmission upgrades, it is straightforward to calculate the expected net benefit as $12M NPV under Scenario A, $25M NPV under Scenario B or $50M NPV under Scenario C. These benefits are additional to those set out in Section D2.2.

D3. Effects of the interconnection charge on market investment and operation

55 This section assesses the efficiency of the effects of the current interconnection charge on electricity market investment and operation.

56 The RCPD allocation of the interconnection charge affects behaviour in various ways, and has the effects of:

a. incentivising a reduction in demand (net of embedded generation) at regional peak times;

b. potentially deferring the need for network investment supporting the upper North Island (UNI) and upper South Island (USI); and

c. potentially deferring the need for peaking generation investment, through incentivising peak-time generation operation and demand reduction.

57 The interconnection charge is ultimately passed on to the majority of end consumers in a variabilised form. This has the further effect of incentivising mass-market consumers to reduce demand at all times, resulting in deadweight loss.

58 The analysis considers the effects of current interconnection charging in terms of:

a. the benefit of incentivising an efficient combination of transmission, generation and demand in the UNI and USI (Section D3.2);

b. the cost of incentivising major lower North Island (LNI) consumers to inefficiently shift demand out of RCPD periods (Section D3.3);

c. the cost of incentivising mass-market consumers to inefficiently reduce demand (Section D3.4); and

d. the benefit of deferring investment in generation capacity to meet peak demand (Section D3.5).

59 The analysis does not consider:

a. benefits from affecting investment in the lower North Island (LNI) or lower South Island (LSI) (because the Authority has not been able to identify any potential transmission investments in these regions that could be deferred through a reduction in regional peak demand);[8]

b. costs through incentivising major LSI consumers to inefficiently shift demand out of RCPD periods (because the Authority sees no evidence that parties in the LSI respond to RCPD signals);[9]

c. the possibility that the RCPD charge will incentivise inefficient embedding of new generation (which is best addressed through the Prudent Discount Policy);

[8] No doubt there are potential transmission investments in the LNI or LSI that can be deferred by managing peak demand at a single node (such as Central Park), or by managing peak demand in a local area (such as the Bay of Plenty) net of all generation in that area. But the Authority is not aware of any potential investments whose need is driven by peak demand across the entire LNI or entire LSI, gross of grid-connected generation.

[9] This is likely to be a result of the LSI RCPD signal being based on 100 trading periods rather than 12, making it difficult for distributors to respond effectively, and the absence of major direct-connect customers who are willing and able to quickly drop a substantial proportion of their load.

d. the possibility that the RCPD charge will incentivise direct-connect consumers to inefficiently disconnect from the grid and operate islanded (which is not considered to be a material risk); or

e. the potential benefit in terms of incentivising distributors to maintain their load control capability (which is difficult to quantify).

D3.1 Key findings

60 Current interconnection charging arrangements are expected to result in:

a. a net cost on the order of $5M (NPV) through incentivising major LNI consumers to shift demand out of RCPD periods;

b. a deadweight loss on the order of $30M (PV) through incentivising mass-market consumers to inefficiently reduce demand;

c. possible net benefits in the millions of dollars (NPV) in the short to medium term, to the extent that they incentivise an efficient combination of transmission, generation and demand in the UNI (and perhaps also the USI); and

d. potentially substantially higher net benefits, to the extent that they incentivise an efficient combination of transmission, generation and demand in the longer term (though there is also a risk that the incentive will become excessively strong and result in outcomes such as an inefficiently high level of embedded generation in the UNI and USI).

61 The following sections set out how these costs and benefits are estimated.

D3.2 Cost-benefit of reducing the need for interconnection investment serving the UNI and USI

62 The RCPD allocation of the interconnection charge incentivises offtake customers in each of the four transmission regions (UNI, USI, LNI and LSI) to reduce their contribution to regional peak demand. This may be efficient if:

a. some transmission investment needs are driven by regional peak demand growth;

b. participants respond to the RCPD incentive[10], resulting in regional peak demand that is lower than it would otherwise have been; and

c. the benefit of reducing the need for investment exceeds the cost of reducing demand.

D3.2.1 Upper North Island

63 The above conditions appear to hold for the UNI (though to varying degrees throughout the region).

64 The need for interconnection investment to serve the UNI is in large part driven by regional peak demand growth.

65 It is likely that the next major transmission upgrade in the UNI (other than those that are already committed) will be the installation of additional NRS at a cost anticipated to be in the range of $50-100M.[11] In the absence of generation changes in the region, and providing reactive loads are appropriately managed, the business case for such investment would be based in large part on growth in regional peak demand.

66 The need for more substantial future upgrades such as the conversion of the NIGUP to its construction voltage of 400 kV[12] or the construction of a second 220 kV circuit from Pakuranga to Penrose[13] would also be driven by growth in regional (or subregional) peak demand.

67 A predictable reduction in UNI regional peak demand of about 30 MW (relative to what it would otherwise have been) would counter a year's demand growth,[14] and could therefore be expected to allow deferral of NRS investment by a year, resulting in a deferral benefit on the order of $4M PV.

68 One way to achieve such a reduction in UNI peak demand would be for offtake customers in the region to shift several hundred MWh of demand out of peak periods. (The exact amount of demand shifted would depend on the shape of the load duration curve and the extent to which customers were able to predict when peaks will occur). This could result in a combination of:

a. a cost to direct-connect customers (including New Zealand Steel or the Marsden refinery or both) as a result of rescheduling production; and

b. a nonfinancial cost to mass-market customers, e.g. through having their electric water heaters turned off.

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10 Anecdotally some distributors do not respond to RCPD charges, since they are a pass-through cost under Commerce Commission regulatory arrangements.

11 Page 48 of Transpower's Annual Planning Report 2012 suggests 'a mixture of capacitors and dynamic support such as STATCOMs'.

12 http://www.ea.govt.nz/document/241/download/industry/ec-archive/grid-investment-archive/gup/2005-gup/

13 http://www.ea.govt.nz/document/6979/download/industry/ec-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/

14 Assuming demand in the region continues to grow at long-term historical rates.

69 However, even if a load reduction of 600 MWh p.a. was required to reduce peak load by 30 MW and the unit cost was as high as $300/MWh,[15] the total cost over the next decade would only be about $1.3M PV – lower than the estimated deferral benefit of $4M PV.

70 The conclusion is that the benefit of reducing the need for investment exceeds the cost of reducing demand in the UNI – even when only the benefit of postponing the next tranche of NRS investment is considered. It is likely that there are other benefits in terms of:

a. deferring more major UNI transmission investment that could be required in the longer term; or

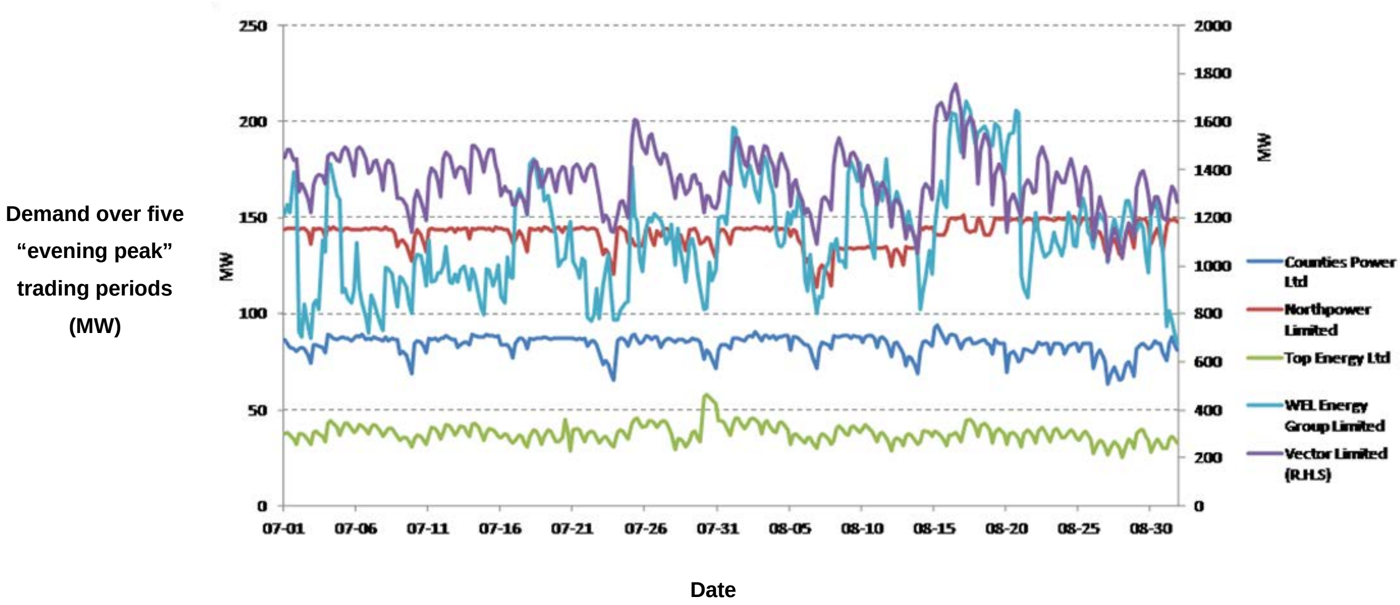
b. deferring distribution network investment; or

c. both a and b.

71 The extent to which these benefits could be captured would depend on where the investment was located within the region.

72 There is evidence that at least some UNI offtake customers respond to the RCPD incentive. Some distributors (including Counties Power and Northpower) demonstrably use load control to reduce their contribution to regional peak.

Contributions to UNI peak demand, by distributor network



(Source: RCPD data supplied by Transpower.)

73 This plot shows peak demand for a two-month period covering July-August 2008 (chosen as an example). WEL (light blue) and Vector (purple) appear to have quite 'natural' demand profiles, with peaks apparently driven largely by weather conditions – but Northpower (red) and Counties (dark blue) are clearly controlling load to a preset cap. Northpower increases its cap slightly following the mid-August cold snap.

74 It is not clear how much higher Northpower and Counties' demand at regional peak times would be if there was no RCPD charge. However, based on the plot above, it would not seem unreasonable to suggest that the difference would be at least 30 MW and therefore that UNI transmission upgrades would be required at least a year earlier without RCPD.

[15] Probably an overestimate of the cost of domestic load control.

75 It may be the case that other UNI distributors or direct-connect consumers (such as New Zealand Steel) or both respond to RCPD signals. The Authority has not seen clear evidence of such response in the UNI, but cannot rule out the possibility that it occurs. The parties concerned will be best placed to explain whether they respond (and if so, how).

76 RCPD signals may also encourage parties to locate new peaking generation investment in the UNI (embedded into a local network, so that it can be used to reduce RCPD) in preference to the LNI.[16] For instance, Trustpower's recent investment in the Bream Bay peaker may help to defer the need for UNI transmission investment, and may have been supported in part by revenues stemming from its ability to reduce RCPD charges.

77 The conclusion is that the current RCPD charge is efficient in terms of reducing the need for interconnection investment serving the UNI, resulting in a net benefit in the millions of dollars (NPV) through deferring the next tranche of reactive investment, and potentially substantially more in the longer term.

78 There is a risk, however, that if the level of the RCPD charge was to rise substantially (e.g. as a result of additional transmission investment) or distributors became more exposed to transmission charges, or both, the level of response to RCPD could increase past the efficient level and cause a net economic cost.

D3.2.2 Upper South Island

79 The need for interconnection investment to serve the USI is also largely driven by regional peak demand growth, with periodic NRS investment needs, and the possibility of upgrades to key transmission circuits in the longer term.[17]

80 It is a matter of record that some USI distributors respond to the RCPD incentive. There is a long history of "peak-shaving" load management on the Orion network. Presumably, Orion would not go to such lengths to manage peak demand if not for peak-based transmission charges. More recently, Orion and other USI distributors have cooperated to control regional peak.[18]

81 In the aftermath of the Canterbury earthquake, however, the Authority hesitates to speculate about:

a. USI transmission investment needs over the next 20 years (beyond what is already committed or in the approval process);

b. how USI peak demand (which is currently depressed) may change; or

c. the cost-benefit of using load control or new embedded generation to defer USI transmission investment.

82 These issues will play out over the next few years.

[16] A peaking generator could still operate to reduce RCPD charges if it was located in the LNI or LSI, but it would need to operate for more trading periods per year in order to do so.

[17] http://www.gridnewzealand.co.nz/f4827,71551667/USI_MCP_consultation_document.pdf

[18] http://www.oriongroup.co.nz/load-management/Upper-south-island-load-management.aspx

D3.3 Cost of incentivising direct-connect consumers in the LNI to reduce demand at regional peak times

83 It appears to have been intended that there would not be a response to RCPD signals in the LNI and LSI regions[19] – and hence the choice of 100 RCPD periods in these regions, as opposed to 12 RCPD periods in the UNI and USI.

84 Nonetheless it appears that some LNI direct-connect consumers do respond to RCPD by reducing their contribution to regional peak demand.

85 Such responses may result in wealth transfers on the energy market, and potentially also in increased production costs for the parties reducing load during RCPD periods. However the inefficiency is probably relatively small – since in order to respond to RCPD, it is only necessary to shift load to non-RCPD periods, rather than to reduce total consumption. As an indication, shifting 50 MW of load in 200 trading periods per year at a net cost of $100/MWh would result in a total inefficiency of $0.5M p.a. (or about $5.5M NPV).[20]

86 Large consumers would be willing to incur such a cost because they would be compensated by a greater reduction in interconnection charges (in the example above, roughly $4M p.a.). Nonetheless, from a national perspective, the cost represents an inefficiency (whereas the reduction in interconnection charges is just a wealth transfer).

87 It may be the case that other LNI or LSI distributors or direct-connect consumers respond to RCPD signals. The Authority has not seen clear evidence of such response, but certainly cannot rule out the possibility that it occurs. The parties concerned would be best placed to explain whether they respond (and, if so, how).

D3.4 Cost-benefit of incentivising most mass-market consumers to reduce demand at all times

88 RCPD charges paid by distributors are ultimately passed through to mass-market consumers, sometimes in a variabilised form. This variable price is inefficient in that it does not reflect a variable cost to the distributor. On first principles, the outcome could be expected to be an inefficiently low level of mass-market consumption at all times.

89 The Authority understands that residential and some small commercial customers typically receive transmission charges in a variabilised form; larger commercial and industrial customers more often in a fixed form.

90 The deadweight loss is estimated at $2.7M p.a. (or about $30M PV over 20 years), based on the following assumptions:

a. total consumption of mass-market consumers paying transmission charges in a variabilised form is about 20 TWh p.a.;

[21] Based on a near-future scenario in which $450M p.a. of interconnection charges are allocated to distributors (excluding charges paid by direct-connect customers).

[21] Based on a near-future scenario in which $450M p.a. of interconnection charges are allocated to distributors (excluding charges paid by direct-connect customers).

b. for such consumers, the portion of the variable component of their bill that results from the interconnection charge is $15/MWh;[21]

c. the total price they pay, if converted into variable terms, would be $200/MWh; and

d. the elasticity of demand is -0.26.[22]

91 Based on these assumptions, such consumers pay 6.8% more than they would if there was no transmission charge and consume 1.8% less – for a total reduction in consumption of 350 GWh p.a. The deadweight loss is 0.5 x increase in price x reduction in consumption, or $2.7M p.a.

[21] Based on a near-future scenario in which $450M p.a. of interconnection charges are allocated to distributors (excluding charges paid by direct-connect customers).

[22] As used in the TPAG report.

D3.5 Benefit of deferring peaking generation investment

92 It is possible that RCPD signals may have beneficial effects in terms of deferring peaking generation investment, by:

a. incentivising direct-connect consumers to reduce demand at peak time;

b. incentivising distributors to maintain load control capability and control load at peak time;

c. incentivising generators to invest in embedded generation and run it at peak time;[23] and hence

d. mitigating island-wide capacity scarcity and reducing the need for additional peaking generation.

93 However, the Authority is not convinced that RCPD provides a significant net benefit in this regard, for the following reasons:

a. regional peak time may not be coincident with island peak time;

b. island-wide capacity scarcity may not be coincident with island-wide peak demand (instead being driven by generation or transmission unavailability or both);

c. even without RCPD, the energy spot price would already provide:

  - direct-connect consumers with a broadly efficient incentive to reduce demand;
  - generators with a broadly efficient incentive to invest in embedded generation and run it; and
  - retailers with a broadly efficient incentive to control load (or seek to contract with distributors to control load)

  at times of island-wide capacity scarcity; and

d. RCPD may in fact discourage the use of load control in response to energy spot prices, since it provides a more cost-effective use for the controlled load (i.e. reducing transmission charges).

--- This concludes Appendix D. Key findings are summarised in Section D1.2. ---

[23] I.e. in order to be paid to reduce some offtake customer's RCPD charges.