Transmission Pricing Methodology Review: TPM options

Working paper

16 June 2015

Market Design

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Executive summary

Introduction

1.1 The Electricity Authority (Authority) is reviewing the guidelines that Transpower and the Authority must follow in setting the transmission pricing methodology (TPM). The TPM determines the allocation of the costs of Transpower's transmission services among its transmission customers.

1.2 The Authority considers that there is potential for alternative options to the current TPM to better promote the Authority's statutory objective, contained in section 15 of the Electricity Industry Act 2010, of promoting competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

1.3 Specifically, the Authority considers that the TPM could be more dynamically efficient by better promoting efficient investment, ensuring lowest cost development of transmission and other electricity assets over time. These dynamic efficiency gains would benefit electricity consumers in the long-term.

1.4 This working paper sets out three potential options for the TPM. The Authority is consulting on the three options to help it determine which option would better promote the statutory objective compared with the others. The Authority has not formed a view, at this stage, on which should be the preferred option.

1.5 The Authority also welcomes comments on whether there are alternative options, including variations on the options included in this working paper, which should be preferred or considered further.

1.6 The Authority is also considering whether any potential change to the TPM should be undertaken in a way that reduces the extent to which changes result in 'winners and losers'. This could be done, for example, by applying any proposed new methodology to new assets only, capping price increases, or including transitional provisions to smooth the impact of the proposed changes on transmission charges. At this stage the Authority has not formed a view on whether potential price changes should be mitigated or, if so, how.

1.7 The next stage in the TPM review process will be to prepare, and then consult on, the second issues paper. The second issues paper will include the Authority's TPM reform proposals and, if applicable, related draft TPM guidelines.

The Authority is currently considering Transpower's TPM operational review

1.8 In 2014/15, Transpower undertook an operational review of the TPM. Transpower submitted a proposed variation to the TPM, comprising a number of components, in February 2015, and submitted additional components in March.[1]

[1] http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/.

The Authority has consulted on four of the components already, and will shortly consult on one further component.[2]

1.9 Transpower's operational review was limited to determining whether opportunities existed for "fine tuning" the TPM, within the constraints of the existing TPM guidelines.[3]

1.10 Transpower's operational review highlighted that the TPM has not adapted to changes in transmission investment, resulting in pricing signals that are too strong. Its review also provided evidence that there are problems with the current High Voltage Direct Current (HVDC) and interconnection (Regional Coincidental Peak Demand (RCPD)-based) charges.

1.11 Transpower's operational review provides an opportunity to realise some of the potential efficiency gains from changes to the TPM earlier than possible under the Authority's review.

1.12 At this stage, the Authority expects to make decisions on Transpower's proposed variation before the release of the second issues paper. If the Authority decides to amend the Electricity Industry Participation Code (Code) to implement some or all of the components of Transpower's proposed variation, the amendment would result in a revised, and potentially enhanced, version of the TPM. This would change the counterfactual for evaluating any alternative option(s).

The Authority's TPM review is warranted by a material change in circumstances

1.13 Clause 12.86 of the Code states that the Authority may review an approved TPM if it considers there has been a "material change in circumstances".

1.14 The Authority considers that there has been a material change in circumstances. In particular, the Authority considers the impact of the $2.8 billion worth of major transmission investment approved since 2004 is a material change in circumstances, and is sufficient to warrant a review of the TPM.[4] The greater the revenue recovered through transmission charges, the greater the materiality of the TPM to the achievement of the Authority's statutory objective. Impacts from the investment include:

(a) an increase to Transpower's Regulatory Asset Base (RAB) of 77 percent over the last four years[5]

(b) the increases in Transpower's revenue cap (over the same period as above) set by the Commerce Commission under Part 4 of the Commerce

2 http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/consultations/#c15231.

3 Transpower, 2014/15 TPM operational review: Second consultation paper, 13 November 2014, page 8.

4 The figure has been arrived at by taking the lower of approved value and actual spend for each investment.

5 Transpower's opening RAB is expected to increase from a value of $2,606.7 million in 2011/12 to an expected value of $4,610.2 million in 2015/16, an increase of 77%. Source: Transpower annual regulatory reports, 2011/12 and 2013/14. Note that comparing the two RABs understates the impact of investments on the RAB because the 2015/16 RAB does not incorporate all major capex investments that have been approved since 2004. Further, the impact of the new investment is understated because existing assets in the RAB depreciate, meaning that without any capital investment, the RAB would be expected to decrease from year to year.

Act 1986, known as the Maximum Allowable Revenue (MAR), following the grid investments[6]

(c) as noted by Transpower, "total transmission revenue is significantly higher than when the current TPM was established and, consequently, the RCPD and HVDC pricing signals are much stronger than when they were set"[7]

(d) as noted by Transpower, "A combination of capacity expansion investments and flat demand growth has led to an increase in the interconnection rate (ICR) of more than 60% from $68 per kW in 2008/09 to $114.00 per kW in 2014/15 (both in 2014/15 dollars)"[8]

(e) as noted by Transpower, "A combination of the costs associated with the HVDC upgrade, and a reduction in the level of South Island generation attracting the [Historical Anytime Maximum Injection] HAMI charge has resulted in an increase of approximately 60% in the HVDC rate from $27 per kW in 2008 to $44.60 per kW (in 2014/15 dollars)".[9]

1.15 In addition, advances in technology, and the reducing costs of computational power, mean more sophisticated TPM options are now available.[10]

1.16 Finally, the regulatory framework has changed significantly. The Electricity Commission was replaced by the Authority on 1 November 2010, the function of approving grid investments was transferred to the Commerce Commission, and a new statutory objective was adopted for the Authority.

1.17 It is appropriate for the Authority to consider whether the TPM, which was approved by the Electricity Commission in 2007 with reference to its statutory objective, best promotes the Authority's statutory objective.

1.18 Each of the above, separately or together, constitute a material change in circumstances.

Problems with the current TPM

1.19 The Authority appreciates the submissions it has received on the problem definition. The Authority is undertaking further analysis of the problems with the current TPM, in preparation for its second issues paper.

1.20 To assist interested parties to respond to this working paper, the Authority outlines below a preliminary set of updated views on problems with the current TPM.

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6 Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4, available at: http://www.ea.govt.nz/dmsdocument/19119.

7 Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4.3, page 15.

8 Note, the Authority calculates the increase at 68%. Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4.3.1, page 16.

9 Note, the Authority calculates the increase at 65%. Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4.3.2, page 16.

10 The ENA has made similar observations about the potential impact of smart metering on distribution pricing. The advances in smart metering technology "unlocks the use of alternative and more cost reflective pricing approaches" and "allows pricing to be more closely aligned with the costs of providing electricity services": ENA, Distribution Pricing: a discussion paper, 11 May 2015, paragraph 39.

1.21 The substantial investment in the transmission grid in recent years has contributed heavily toward a nearly 70 percent increase in the strength of the transmission (interconnection and HVDC) pricing signals, encouraging potentially inefficient and unnecessary investment and activity to avoid the charges.[11]

1.22 More than $1.3 billion of transmission investment has been commissioned in the upper North Island (UNI) since 2004.[12] This accounts for 29 percent of Transpower's RAB (in 2015/16), or 48 percent of approved transmission investment since 2004.

1.23 The $1.3 billion of investment commissioned in the UNI broadly translates to an increase in Transpower's MAR of $221 million per annum. Of this, only $87 million or 39 percent is paid for through increases in charges to the UNI. Transmission charges in the lower North Island (LNI), upper South Island (USI) and lower South Island (LSI) have increased by 61 percent on average, largely to pay for the cost of investment in the UNI and, in particular, in the Auckland region.[13]

1.24 Transpower has assessed that the split in book value of transmission assets between the North Island and South Island has gone from 60:40 in 2007 to 79:21 in 2014, while the split in charges of 66:34 has remained relatively unchanged.[14]

1.25 The Authority has previously noted: "An issue often raised with New Zealand's postage stamp interconnection charge is that it results in customers in areas not needing increases in capacity contributing to fund expansions in areas, like Auckland, where capacity is being increased".[15]

1.26 Vector has, similarly, expressed concern: "Complaints that the costs of network upgrades in the North Island are shared by consumers in both the North and South Islands are common", and bring into question "the efficacy of the current postage stamp pricing of the AC network". Vector cited the example of Network Waitaki incurring a 23.4% increase in transmission charges "largely to pay for upgrades into the Auckland region", "while projects they consider vital to the long-term security and reliability of supply to the Waitaki district, had been deferred because they were deemed to be of lower priority by Transpower".[16]

1.27 The Authority has substantial concerns about the durability of a TPM that does not adapt to increases in transmission investment, and where increases in the investment needs of one region result in substantial price increases for other regions.

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11 Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, sections 4.3.1 and 4.3.2, page 16.

12 This does not include investments, such as the Wairakei Ring, that are located outside the UNI but were undertaken at least in part to serve UNI demand for transmission services.

13 Interconnection revenue in relation to the LNI, USI and LSI regions increased by 62%, 59%, and 59% respectively or 61% on average between 2008/9 to 2015/16.

14 E-mail from Transpower, EA TPM Review: request for information, 28 May 2015. Refer also to: Transpower, Proposal to amend the Electricity Industry Participation Code 2010, TPM Operational Review: NZAS Summer Load Limit, 13 February 2015, footnote 9, page 5.

15 Electricity Authority, Decision-making and economic framework for transmission pricing methodology review, 26 January 2012, paragraph 2.3.13.

16 Vector, Submission to the Electricity Authority on the Decision-making and economic framework for transmission pricing methodology review, 24 February 2012, paragraphs 50 and 51.

1.28 By way of a further example, power from North Island generators is often transferred across the HVDC link when South Island hydro lakes are at low levels. North Island generators pay nothing for using the HVDC link to send their power south as all HVDC costs are allocated to South Island generators. Similarly, load in both islands receives electricity via the HVDC but does not contribute to its costs. Also, some grid-connected industrial consumers in the North Island have been able to avoid interconnection charges by altering their demand patterns.

1.29 The socialisation of transmission charges weakens the incentives of the parties that are recipients or beneficiaries of potential new investment to scrutinise whether the investment is economic or optimal. Their incentives to scrutinise investments may be limited to ensuring the benefits they would receive exceed their share of the additional costs (which can be a small amount or almost nothing at all when costs are smeared).

1.30 The Authority considers that transmission charges have an important role to play in promoting efficient investment by supporting the discovery of efficient transmission investments.

The Authority is seeking views on three potential TPM options

1.31 The Authority has consulted on, or considered, a wide range of options for reform of the TPM, including but not limited to:

(a) the Transmission Pricing Advisory Group (TPAG) recommendations

(b) the Authority's original scheduling, pricing and dispatch (SPD) method proposal, included in the October 2012 issues paper

(c) various beneficiaries-pay options, including area-of-benefit (AoB), flow tracing, and further versions of the SPD method

(d) long-run marginal cost (LRMC) options including tilted postage stamp, and

(e) other options put forward by submitters.

1.32 Following consideration of submissions in relation to the TPM review to date, the Authority is exploring the possibility of applying the existing connection charge, and several possible new charges. The possible new charges are a deeper connection charge, a kvar charge, an Area of Benefit (AoB) charge, an LRMC charge, an SPD charge (substantially different from the original SPD proposal), a capacity-based residual charge, and a revised LCE credit. The charges included in each option are set out in Table 1.

1.33 The Authority has applied the Decision-Making and Economic (DME) framework it developed to assist it to make decisions on potential TPM options.[17]

1.34 The Authority's options consist of a Base Option, the Base Option + LRMC and the Base Option + SPD. The three options, and how they relate to the DME framework hierarchy of preferred approaches, are depicted in Table 1.

[17] Electricity Authority, Decision-making and economic framework for transmission pricing methodology, Decisions and reasons, 7 May 2012, available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/economic-framework-decision-making/.

Table 1: DME framework and TPM options

DME framework		Base Option	Base Option + LRMC	Base Option + SPD
Market	LCE credit	✓	✓	✓
Market-like	The existing connection charge	✓	✓	✓
	Deeper connection charge	✓	✓	✓
	LRMC charge		✓	
Exacerbators-pay	kvar charge	✓	✓	✓
Beneficiaries-pay	AoB charge	✓	✓	✓
	SPD charge			✓
Alternative approaches	Capacity-based residual charge	✓	✓	✓

1.35 Each of these three options, and their charging components, are detailed below.

1.36 The **Base Option** consists of the existing connection charge, a new 'deeper connection' charge, a kvar charge, an AoB charge, a capacity-based residual charge and LCE credit.

1.37 The new *'deeper connection' charge* would extend the concept of connection deeper into the grid than the current connection charge.

1.38 The charge would apply to assets that are currently defined as interconnection assets but are predominantly used by a small number of parties (either load or generators or both). The Authority considers these assets should be treated as deeper connection to help ensure the full economic costs of connecting to the grid are recovered from connecting parties.

1.39 It is proposed that assets subject to deeper connection charges, and the parties responsible for paying these charges, would be identified using flow tracing. The Herfindahl-Hirschman Index (HHI) would be used to determine the concentration of electricity flows in relation to a transmission asset, and the concentration rate would distinguish deeper connection assets from interconnection assets. Only assets with a high concentration of flows would be subject to the deeper connection charge.

1.40 The Authority considers that applying deeper connection charges in relation to assets used, predominantly, by a small number of parties would be market-like.

1.41 The *kvar charge* would recover the costs of static reactive support. The Authority considers this to be an exacerbators-pay charge.

1.42 The *area-of-benefit-based (AoB) charge* would recover the revenue for large recent and future investments (or in respect of assets within those investments) beyond the coverage of the deeper connection charge. The AoB charge is an ex-ante beneficiaries-pay charge.

1.43 The AoB charge would be paid by parties assessed as benefiting from an interconnection investment at the time the investment was approved. The parties subject to the AoB charge would be reviewed where there had been a substantial change in benefits (measured against a pre-defined threshold). Incorporating such a mechanism in the AoB charge would help ensure the charge is durable if there are significant changes to the grid and the parties using the assets.

1.44 The AoB charge is based on what was referred to in the beneficiaries-pay working paper as the "Grid Investment Test (GIT)-based charge". However, unlike the GIT-based charge, which applied to reliability investments only, the AoB charge would apply to both economic and reliability investments. This would mean a consistent charging approach for both types of investments.

1.45 The *postage stamp (flat rate) capacity-based residual charge* would recover any revenue shortfall from the other charges.

1.46 Because the deeper connection charge and the AoB charge should provide the signals necessary to promote efficient investment, the residual charge should be designed to limit the distortion in use of the grid resulting from the imposition of the charges. The Authority considers that only charging load would be less distortionary than charging load and generation or only charging generation.

1.47 The *loss and constraint excess (LCE)* attributable to a connection or deeper connection asset would be credited against charges of customers that pay for that asset, and the remaining LCE would be credited in bulk against Transpower's remaining MAR (that is, MAR not related to connection and deeper connection assets).

1.48 The **Base Option + LRMC** is the same as the Base Option except it includes an LRMC charge.

1.49 The *LRMC charge* would signal the cost of transmission investments in advance of those investments taking place (reflecting the cost of the future investments).

1.50 The LRMC charge could create efficient incentives for parties to alter their demand for transmission services to forestall the need for the transmission investment.

1.51 Once the investment has been made, the Authority is proposing that its costs would be recovered through the AoB charge.

1.52 The **Base Option + SPD** is the same as the Base Option except it includes an *SPD charge* to recover the revenue for large recent and future transmission investments beyond the boundary of the deeper connection charge.

1.53 The SPD charge is a dynamic charge that identifies beneficiaries on a half-hourly basis. The charge would be applied on a 3-year rolling average basis after transmission investments were commissioned. It is an ex-post beneficiaries-pay charge.

1.54 The design of the SPD charge is similar to that proposed in the beneficiaries-pay working paper. However, it is now proposed that the calculation of the SPD charge would be according to net rather than gross benefits, and the capping period would be extended to one month. An AoB charge would be applied to large recent and future transmission investments for which the SPD charge raises insufficient revenue to fully cover Transpower's MAR.

The Authority is considering the coverage of the AoB and SPD charges

1.55 The AoB and SPD charges are beneficiaries-pay charges.

1.56 While the Authority is still considering the potential applicability of new charges to existing assets, and transitional arrangements, charges could apply to the following investments (or in respect of assets within those investments) if they are not subject to the deeper connection charge:

(a) new investments with a cost exceeding $20m, where "new" means investments approved or commissioned after the publication of guidelines for a new TPM

(b) historical investments both approved and commissioned since 28 May 2004 (but before the publication of guidelines for a new TPM) with a cost above $50m

(c) Pole 3, and possibly Pole 2, of the HVDC link.

1.57 Historical investments and Pole 3 are included in the above list as this includes all large investments approved under a regulatory process. Including these investments would help promote consistency of treatment by applying beneficiaries-pay charges to both recent and future investments.

1.58 Pole 2 is included in the above list as it would achieve consistent treatment with Pole 3.[18] Pole 2 and 3 provide the same service – delivery of electricity between the North and South Islands – and, in principle, should be treated like for like in the way they are priced.

1.59 However, changing the charging for Pole 2 may not be able to be justified on dynamic efficiency grounds. If Pole 2 was not subject to the AoB or SPD charge, one option would be to retain Pole 2 in respect of the existing HVDC charge (or any replacement HVDC charge arising from the HVDC component of Transpower's proposed variation), including continuing to apply this charge to South Island generators.

The Authority's qualitative assessment of options suggests they all could better promote the statutory objective

1.60 The Authority considers that each of the three options for amending the TPM could substantially address the problems identified with the current TPM. The Authority also considers that the three options are proportionate to the scale of problems with the current TPM.

1.61 The Authority's qualitative assessment of the three options suggests they all could potentially better promote overall efficiency of the electricity industry than does the current TPM.

[18] The Authority estimates that Pole 2 has a revenue requirement of approximately $55M per annum.

1.62 Each of the options would create a stronger link between the transmission charges and the costs that are driven by use of the grid. The costs of future grid investment, in particular, would be borne by the grid-users that benefit from the investment. More cost-reflective pricing, and a tighter link to benefits, should result in more efficient use of the grid, and more efficient investment. More efficient investment would particularly benefit consumers over the long-term.

1.63 The Authority agrees with the Electricity Networks Association (ENA) that "Cost reflective … pricing structures can assist consumers to make more efficient consumption and investment decisions where electricity prices better reflect underlying costs of supply" and "In addition, electricity generators, transmission grid owners and distributors can make more efficient investments if consumers respond to cost reflective pricing signals".[19]

1.64 The Authority has not formed a view on which option should be preferred. Submissions on this options working paper will help assist the Authority to form a view on which of the options would better promote the Authority's statutory objective, compared to the others.

1.65 The Authority recognises that there are a large number of design choices for each of the components of the proposed options, and each of the components has potential merit in its own right. Some of the components could be used more extensively than the Authority is presently proposing. Some could also be included as add-ons to the existing TPM.

1.66 The Authority welcomes comments on whether other options or variations on the three options should be preferred or considered further.

1.67 The Authority will undertake quantitative cost benefit analysis (CBA) to assess options it considers as part of the second issues paper. The CBA will help determine whether the TPM should be amended or replaced. The counterfactual used for the assessment will either be the status quo or a revised status quo if the Authority approves some or all of the components of Transpower's proposed variation to the TPM.

1.68 Given each of the three options has the same base (revised treatment of LCE, kvar charge, deeper connection, AoB, and residual charge), which of the options should be preferred depends on whether an LRMC or SPD charge would provide incremental net benefits in addition to the Base Option. Put another way, are LRMC or SPD charges complementary to the design of the Base Option?

1.69 LRMC charging options have had strong support, particularly from electricity networks including from the ENA and PwC (representing 21 Electricity Distribution Businesses (EDBs)), with the ENA and Transpower both pointing out LRMC is market-like and ranks higher in the DME framework than beneficiaries-pay options.

1.70 The ENA considers that "An LRMC charge would provide transmission users with price signals that approximate the long run costs of their transmission usage at peak times" and that "This is desirable from a dynamic efficiency perspective".[20]

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19 ENA, Distribution Pricing: a discussion paper, 11 May 2015, paragraph 27.

20 ENA, Submission on Transmission Pricing Methodology: Beneficiaries-pay options, 25 March 2014, paragraph 46.

1.71 The Authority raised concerns, in the LRMC working paper,[21] about whether robust estimates of LRMC can be produced that could be relied on for transmission pricing purposes. The Authority continues to hold these concerns.

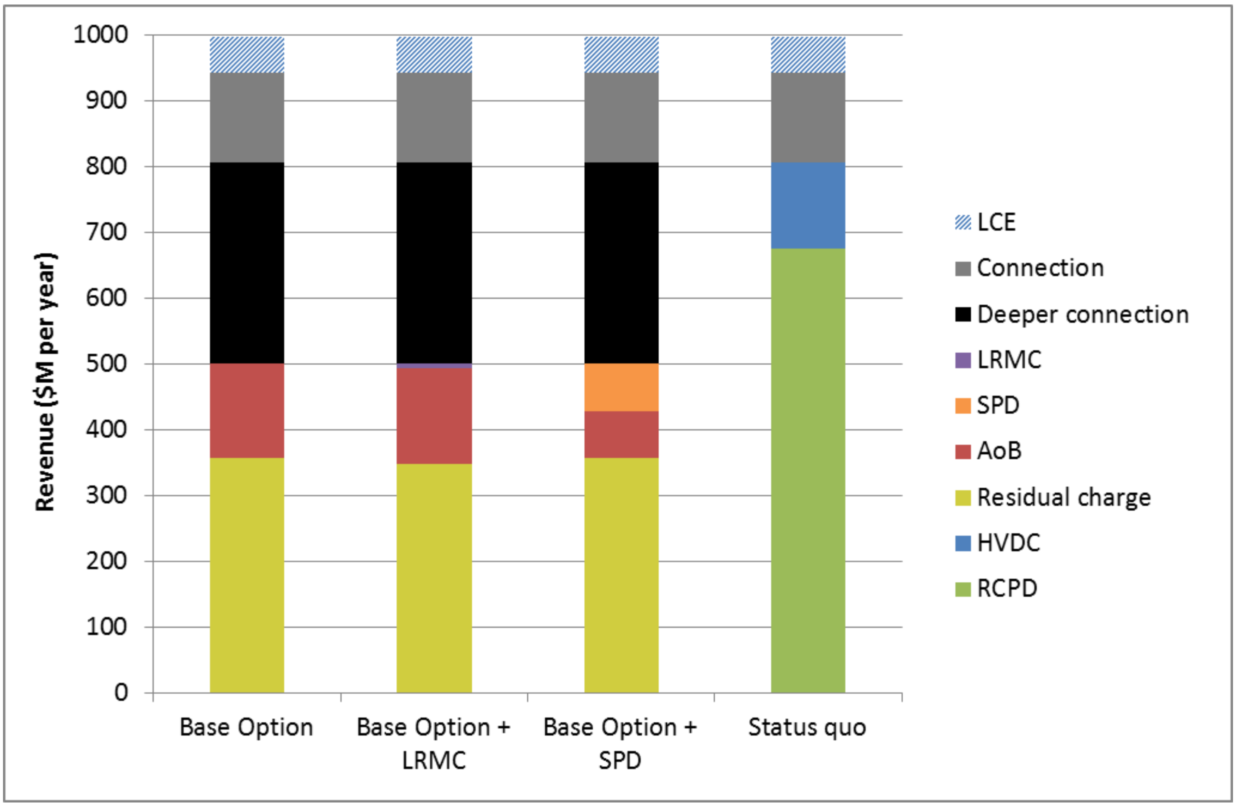
1.72 The attraction of an SPD charge is that it provides an objectively measurable way of determining the economic benefits parties receive from transmission investment through the wholesale electricity market. The Authority would welcome views on whether an SPD charge would be a more feasible approach for charging for economic investments than LRMC or AoB charges.

1.73 The benefit of an SPD charge depends on the extent to which market participants would 'game' the wholesale market to avoid the SPD charges. The Authority has addressed many of the concerns with the original SPD proposal including that it could incentivise gaming, the volatility of the changes, and that the SPD charge would not be known in advance.

Recovery of revenue under the three options

1.74 Figure 1 below summarises how each of the three options, and the status quo, recovers Transpower's MAR.[22]

Figure 1: Breakdown of options by charge[23]



21 Electricity Authority, Transmission Pricing Methodology Review: LRMC charges, working paper, 29 July 2014, sections 7 – 9.

22 All of the Authority's options include a kvar charge for recovering the costs of static reactive support. The kvar charge has not been included in the modelling because the Authority considers income from the charge would be likely to be minimal due to current power factors being close to unity.

23 Note that Transpower's total revenue shown here differs from Transpower's MAR ($909.8M for the 2015/16 pricing year) because the modelling refers to a hypothetical forecast scenario. Refer to Appendix A for more information on modelling assumptions.

1.75 When considering the impact of the options on transmission prices (and ultimately retail prices to consumers), it should be noted that:

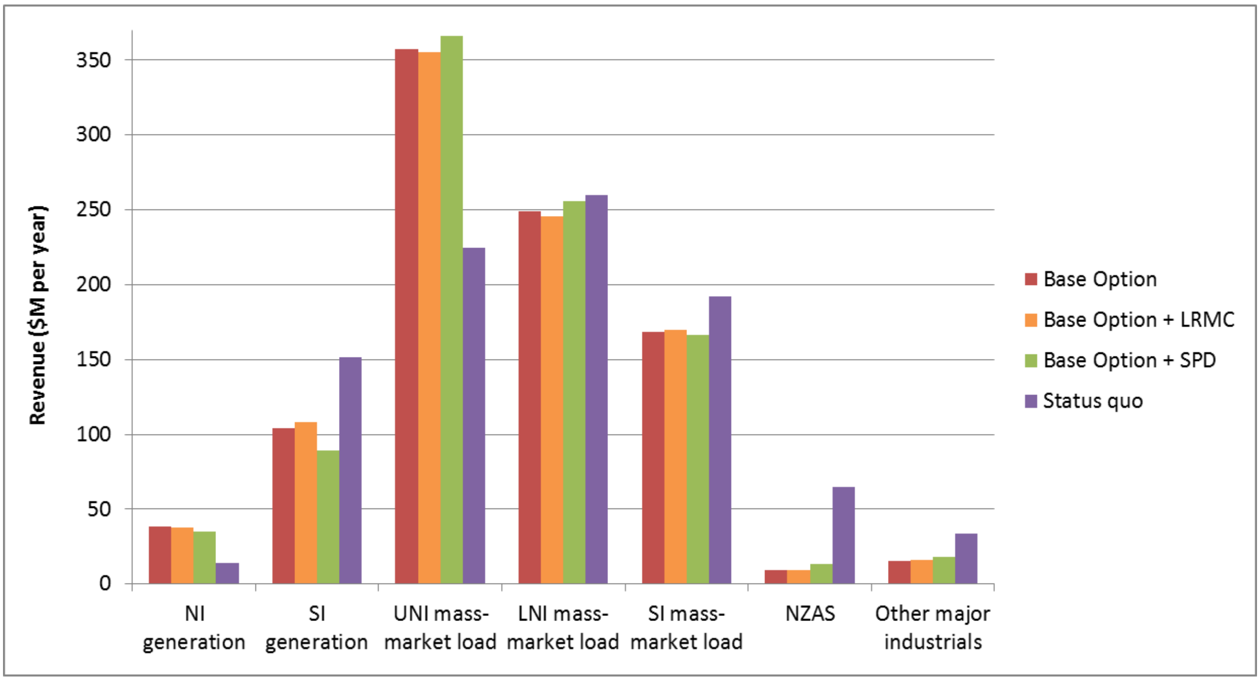
(a) the Authority is considering options for how to apply any new TPM, as well as potential price caps and transition options, which could substantially mitigate potential large changes to transmission charges

(b) the analysis of pricing impacts does not take into account that a more efficient TPM could result in cost and investment savings over the long-term

(c) the pricing impact also does not take into account that there are offsetting benefits/price reductions to consumers from transmission investment. For example, the Wairakei Ring and NIGU investments alone have resulted in a reduction in spot prices (estimated at $12 million per annum by value) and electricity losses (estimated at $20 million per annum by value) in the UNI.[24,25]

1.76 Figure 2 provides a modelled breakdown of revenue received under each option from each group of consumers of transmission services.[26]

Figure 2: Breakdown of options by cost allocation to groups[27]



1.77 Transmission charges would increase in the UNI, where the majority of investment over the last decade has occurred, and in some other locations such as the West Coast and Marlborough. North Island generators, who presently do not contribute to HVDC or interconnection charges, would also bear higher transmission charges.

24 Refer to section 10: Price effects of the options.

25 Similarly, Transpower has estimated that the Wairakei Ring investment has a benefit cost ratio of 7.94 which means that the beneficiaries of the Wairakei Ring would receive substantial net benefits even if they paid the full cost, rather than it being smeared across all load: Castalia, Response to Proposed WACC Amendment, 29 August 2014, Table 3.1.

26 Refer to Appendix E for estimated changes in total transmission charges to individual parties.

27 This excludes revenues recovered through LCE.

1.78 Each option would result in lower transmission charges for consumers in regions such as Christchurch, Hawkes' Bay, Southland, Wellington and parts of the central North Island. Meridian Energy and Pioneer Generation would also incur lower transmission charges, as would most direct connection industrial consumers.

1.79 In general, the options would mean consumers that have benefited from recent transmission investment would experience an increase in transmission charges but consumers who have received relatively little benefit from transmission investment would, in general, experience a decrease in charges. In particular, areas that would experience increased transmission charges as result of transmission upgrades would have benefited from a reduction in wholesale electricity prices as a result of the upgrade, or improved reliability or both.

1.80 The options could result in changes in residential electricity prices as follows:[28]

(a) a reduction of approximately 2.0 percent in electricity charges for residential customers of the following electricity distribution businesses (EDBs): Alpine Energy, Network Waitaki, Orion, PowerNet[29], Waipa Power and Wellington Electricity

(b) roughly the same electricity charges for residential customers of the following EDBs: Aurora Energy, Buller Electricity, Eastland Networks, Electricity Ashburton, Horizon, Mainpower, Network Tasman, Powerco, Scanpower, The Lines Company, Unison[30] and WEL Networks

(c) an increase in electricity charges of approximately 4.5 percent for residential customers of the following EDBs – Counties Power, Electra, Marlborough Lines, Northpower and Vector

(d) an increase in electricity charges of approximately 10 percent for residential customers of the following EDBs: Top Energy and Westpower.

Potential application of new charges under options

1.81 The Authority recognises the view expressed by a number of parties, in response to the 2012 issues paper, that any new charges aimed at promoting dynamic efficiency should only apply to new assets. The Authority also recognises that the three options it is presently considering could result in potential large changes in the allocation of transmission charges and therefore potential price increases for some customers.

1.82 The Authority is considering two possible applications of the new charges proposed under the three options:

(a) Application A: This would involve applying new charges to both existing assets (refer to Table 2) and new assets and investments

(b) Application B: This would involve applying new charges to new assets and investments only, with the costs of existing assets recovered through the existing charges, that is, the connection, interconnection and HVDC

28 Refer to Appendix F for an indication of the effect of the options on residential electricity prices.

29 All references to Powernet throughout this paper include The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland.

30 All references to Unison throughout this paper include Centralines.

charges. New base capex not captured by the deeper connection charge would be recovered through the interconnection charge.

1.83 The detail of how these applications might be applied to the charges under the three options is set out in Table 2. (Note that the distinction between "new" and "existing" assets and investments does not affect the application of the proposed LCE credit, the kvar charge, and the LRMC charge under the Base Option + LRMC.)

Table 2: Possible applications of new charges[31]

Charge	Option	Application A (New charges apply to both existing and new assets and investments)	Application B (New charges apply only to new assets and investments)
Deeper connection charge	All options	Apply to all eligible existing and new assets	Apply only to new assets
AoB charge	All options	Apply to post-2004 investments above $50m, post-new guidelines investments above $20m, and, potentially, Pole 2	Apply only to new investments
SPD charge	Base Option + SPD only	Apply to post-2004 investments above $50m, post-new guidelines investments above $20m, and, potentially, Pole 2	Apply only to new investments
Residual charge	All options	Apply capacity-based charge[32] to recover residual revenue[33]	Recover residual HVDC revenue through current HVDC charge.[34] Recover remaining residual revenue through current interconnection charge,[35] with one exception. The exception is that all load customers must pay at least the variable cost arising from their connection to, and use of, interconnection assets

31 "Investments" are investments approved under a regulatory process (i.e. by the Electricity Commission or the Commerce Commission). Those investments are comprised of "assets", but, more broadly, the term assets is used to denote any physical part of the grid. "New" assets are assets that are upgraded, constructed or replaced, with a commissioning date falling after the Authority had published revised TPM guidelines.

32 That is, the allocation is based on ICPs for most consumers but based on AMD for major industrial consumers.

33 Residual revenue = Transpower’s total revenue requirement less revenue collected from other charges.

34 Subject to changes the Authority may approve as part of the review of Transpower’s proposed variation to the TPM.

35 Subject to changes the Authority may approve as part of the review of Transpower’s proposed variation to the TPM.

1.84 The Authority recognises that a sizable portion of the potential dynamic efficiency benefits from the proposals would arise from application of the charges to new investments.

1.85 However, many of the problems that have arisen with the current TPM relate to how it has applied to recovering the costs of the substantial transmission investment that has occurred over the past decade. Also, applying new charges to existing assets can help promote more efficient investment if the charges assist in improving the quality of future investment decisions.

1.86 Application A would remove any mismatch between current charges and the cost of delivering transmission services that may have accumulated over time. For example, Application A would avoid LNI, USI and LSI customers subsidising post-2004 transmission investment that was predominantly made to meet UNI requirements.

1.87 The Authority would welcome submissions on whether Application A or B should be preferred.

The Authority is considering transition mechanisms

1.88 If the Authority were to decide to implement any of the options contained in this working paper, or alternative changes, it would also consider whether a transition mechanism or price increase cap should be adopted.

1.89 Each of the proposed options in this working paper under Application A could lead to potentially large changes in transmission charges.

1.90 The Authority is considering a variety of transition arrangements for Application A. An important consideration would be the impact of avoiding price increases for some parties but forgoing price decreases for other parties.

1.91 The Authority would welcome submitters' views on whether there should be a transition in relation to Application A and, if so, what this should be.

Changes to the TPM may affect ACOT payments

1.92 Avoided cost of transmission (ACOT) payments are not part of the TPM and the Authority's intended review of the pricing principles under Part 6 of the Code is not part of the TPM review. However, the Authority has provided its views on ACOT because changes to the TPM may have an impact on ACOT payments.

1.93 In particular, since most of the charges under the options considered in this paper are proposed to be calculated on a capacity rather than peak basis, and since ACOT payments to distributed generators are sometimes made on an avoided charges basis, ACOT payments would fall significantly. The exception to this would be if an LRMC charge were introduced, which is proposed to be calculated on a peak congestion basis.

1.94 The fact that ACOT payments are sometimes made for avoided transmission charges rather than actual avoided economic costs is of concern to the Authority. For example, ACOT payments are sometimes made regardless of whether transmission investment is being avoided or postponed. Further, some EDBs have submitted that distributed generation (DG) actually increases the requirement for investment in distribution assets in certain circumstances. This can result in consumers paying higher overall charges (transmission charges plus ACOT payments) than in the absence of some DG.

1.95 If a more cost-reflective and dynamically efficient TPM were introduced, the Authority's concerns about the difference between avoided transmission charges and actual avoided economic costs should be reduced because charges would be better related to costs.

Contents

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ACOT	Avoided cost of transmission
AIC	Average incremental cost
AMD	Anytime maximum demand
AoB	Area-of-benefit
Authority	Electricity Authority
Capex IM	Capital expenditure input methodology
CAPs	Code amendment principles
CBA	Cost benefit analysis
CIC	Customer investment contract
Code	Electricity Industry Participation Code 2010
DG	Distributed generation
DME framework	Decision-making and economic framework
DRC	Depreciated replacement cost
EDB	Electricity distribution business
ENA	Electricity Networks Association
FTR	Financial transmission rights
GIS	Gas-insulated switch gear
GIT	Grid investment test
GWh	Gigawatt hour
HAMI	Historical anytime maximum injection
HHI	Herfindahl-Hirschman index
HVDC	High voltage direct current
IC	Interconnection
ICP	Installation control point
ICR	Interconnection rate
IM	Input methodology
IPP	Individual price path
IR	Instantaneous reserves
kWh	Kilowatt hour
kvar	Kilovolt ampere reactive
LCE	Loss and constraint excess
LMP	Locational marginal pricing

LRIC	Long-run incremental cost
LRMC	Long-run marginal cost
MAR	Maximum allowable revenue
MEUG	Major Electricity Users' Group
MIC	Marginal incremental cost
MW	Megawatt
MWh	Megawatt hour
MRP	Mighty River Power
NAaN	North Auckland and Northland grid upgrade project
NIGU	North Island Grid Upgrade Project
NRS	Network reactive support
PDP	Prudent discount policy
PDWP	Problem definition working paper
PRS	Price-responsive schedule
RAB	Regulatory asset base
RCPD	Regional coincident peak demand
RCPI	Regional coincident peak injection
SFT	Simultaneous feasibility test
SO	System operator
SPD	Scheduling, pricing and dispatch
SRMC	Short-run marginal cost
SRS	Static reactive support
TPAG	Transmission Pricing Advisory Group
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited

2 Introduction

2.1 The Electricity Authority (Authority) is reviewing the guidelines that Transpower and the Authority must follow in setting the transmission pricing methodology (TPM). The TPM determines the allocation of the costs of Transpower's transmission services among its transmission customers.

2.2 The Authority considers that there is potential for alternative options to the current TPM to better promote the Authority's statutory objective, contained in section 15 of the Electricity Industry Act 2010, of promoting competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

2.3 Specifically, the Authority considers that the TPM could be more dynamically efficient by better promoting efficient investment, ensuring lowest cost development of transmission and other electricity assets over time. These dynamic efficiency gains would benefit electricity consumers in the long-term.

2.4 This working paper sets out three potential options for the TPM. The Authority is consulting on these options to help determine which option would better promote the statutory objective compared with the others. However, the Authority welcomes comments on whether there are further alternative options, including variations on the options included in this working paper, which should be preferred or considered further.

2.5 As each of the options includes a deeper connection charge and this is a new proposal, the Authority has produced a companion paper to this options working paper – *TPM options working paper: Companion paper describing the detail of the deeper connection charge, June 2015*. The companion paper contains more detail on the proposed design of this charge.

2.6 Versions of the other aspects of the Authority's TPM proposals, including LCE, AoB charges, SPD charges, LRMC charges and residual charges have been either proposed or discussed in previous TPM consultations.

2.7 The Authority is also considering whether any potential change to the TPM should be undertaken in a way that reduces the extent to which changes result in 'winners and losers'. This could be done, for example, by applying the new methodology to new assets only, capping price increases, or including transitional provisions to smooth the impact of the proposed changes. The Authority has not formed a view on whether potential price changes should be mitigated or, if so, how, at this stage.

2.8 The next stage in the TPM review process will be to prepare, and then consult on, the second issues paper. The second issues paper will include the Authority's TPM proposals and, if applicable, related draft TPM guidelines.

October 2012 issues paper and working papers

2.9 The Authority released an issues paper in October 2012 (October 2012 issues paper).[36] Following consideration of submissions on the October 2012 issues paper and information provided at the Authority's May 2013 TPM conference, the Authority decided to advance the review by developing a second issues paper.

2.10 Before it develops the second issues paper, the Authority is considering and consulting on key aspects of a revised TPM proposal through a series of working papers. The working papers the Authority has completed are:

(a) Cost benefit analysis (CBA): This working paper outlined a revised approach that the Authority intends to apply to the cost-benefit analysis of a revised TPM proposal that will be included in the second issues paper.

(b) Definition of sunk costs: This working paper examined the extent to which the costs involved in providing electricity transmission services are actually "sunk" and the implications for transmission pricing.

(c) Avoided cost of transmission (ACOT): This working paper considered the efficiency implications of any changes to the TPM in relation to ACOT payments.

(d) Loss and constraint excess (LCE): This working paper explored submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals.

(e) Beneficiaries-pay options: This working paper examined options for applying a beneficiaries-pay charge to recover the costs of high voltage direct current (HVDC) and interconnection assets

(f) Connection charges: This working paper examined whether the pool charging approach for transmission connection assets is efficient and whether there is the potential for connection assets to be inefficiently classified as interconnection assets.

(g) LRMC: This working paper examined whether the use of LRMC transmission charges to recover the costs of HVDC and interconnection assets would better promote the Authority's statutory objective than would maintaining the status quo.

(h) Problem definition working paper: This working paper discussed and, to the extent practicable, quantified, problems with the current TPM.

2.11 After consultation on the second issues paper, the Authority will hold a further conference.

What this working paper is about

2.12 This working paper assesses potential options to address the problems identified in relation to the TPM. Each option comprises a package of charges.

2.13 The options have been developed having regard to submitter feedback on the October 2012 issues paper, during the May 2013 conference, and on the above working papers.

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36 Electricity Authority, Transmission Pricing Methodology: Issues and proposal, Consultation Paper, 10 October 2012.

2.14 Submissions on this working paper will help inform the Authority's revised TPM proposal (ie a preferred option, as well as potential alternatives for comparison), and related draft guidelines (if applicable), for the second issues paper.

2.15 The options in this working paper are assessed qualitatively. A quantitative assessment of a preferred option and one or more potential alternatives will be included in the second issues paper.

Submissions on this working paper and the companion paper

2.16 The purpose of this working paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the TPM.

2.17 Submitters proposing alternative TPM options should ensure their proposals are supported, to the extent practicable, by evidence that their alternatives would better promote the statutory objective than the status quo or Transpower's proposed variation to the TPM.

2.18 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "TPM Options working paper" in the subject line.

2.19 If submitters are not able to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

2.20 Submissions should be received by 5pm on 11 August 2015 (8 weeks).

2.21 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2.22 Your submission will be made available to the general public on the Authority's website. Submitters should indicate any documents attached in support of the submission in a covering letter, and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

3 Regulatory framework

Introduction

3.1 This section first summarises, at a high level, how decisions are made on the TPM.

3.2 The remainder of the section then discusses the following matters, which relate to the basis for, and scope of, the Authority's review:

(a) material change in circumstances threshold

(b) the use of the Decision-Making and Economic framework (DME framework)

(c) how the Authority has interpreted the Authority's statutory objective in the context of transmission pricing

(d) efficient investment, the Authority, and the Commerce Commission

(e) detail of options and specificity of the guidelines, and

(f) Transpower's operational review.

Decisions on the TPM

3.3 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Electricity Industry Participation Code 2010 (Code) are consistent with the Authority's statutory objective in section 15 of the Act.

3.4 The TPM is part of the Code, so any amendment to the TPM, or to the TPM guidelines, must be consistent with the Authority's statutory objective.[37]

3.5 In order to assist the Authority to make decisions about the TPM, including guidelines for the development of a new TPM, the Authority developed, and consulted on, a decision-making and economic framework in May 2012.[38] The DME framework sets out the Authority's interpretation of its statutory objective in the context of transmission pricing. It also sets out the Authority's views on how it will decide between options for allocating the costs of transmission services.

3.6 In developing the second issues paper, the Authority will continue to be guided in its decisions by the DME framework. The Authority will make decisions about the development of the TPM, including the TPM guidelines, according to the Code Amendment Principles (CAPs) in the Authority's Consultation Charter[39] and the Authority's statutory objective.

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37 Electricity Authority, Interpretation of the Authority's statutory objective, 14 February 2011, is available at: http://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/.

38 Electricity Authority, Decision-making and economic framework for transmission pricing methodology, Decisions and reasons, 7 May 2012, available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/economic-framework-decision-making/.

39 Electricity Authority, Consultation Charter, 19 December 2012, available at: http://www.ea.govt.nz/about-us/strategic-planning-and-reporting/foundation-documents/.

Material change in circumstances

Threshold test

3.7 Clause 12.86 of the Code states that the Authority may review an approved TPM if it considers there has been a material change in circumstances.

3.8 In the October 2012 issues paper, the Authority set out the matters that it considered constituted a material change in circumstances.[40] In summary, the Authority considered that, whether regarded individually or together, the following changes constitute a material change in circumstances:

(a) over $2 billion worth of transmission investment has been approved, which has included major investments such as the HVDC pole 3 project, and the North Island grid upgrade

(b) the significant changes to the regulatory framework, with the Authority replacing the Electricity Commission from 1 November 2010, and the function of approving grid investments being transferred to the Commerce Commission

(c) advances in technology, and reducing costs of computational power, have made available more sophisticated means of allocating transmission costs.

3.9 A number of submitters on the October 2012 issues paper and the working papers submitted that the Authority had failed to demonstrate the "material change in circumstances" threshold had been met, and, therefore, that the Authority did not have grounds to review the TPM.

3.10 Having considered those submissions, the Authority remains of the view that there has been a "material change in circumstances". Each of the above, separately or together, constitutes a material change in circumstances. The Authority does, however, wish to elaborate on two items.

3.11 The former Electricity Commission made a final decision on the transmission pricing methodology in June 2007. The Electricity Governance Rules were amended to include the TPM in September of that year, and the TPM applied from April 2008. The first major grid investment approved by the Electricity Commission, the North Island grid upgrade, was approved in July 2007. After that, other significant investments, including the Otahuhu substation diversity project, the North Auckland and Northland (NAaN) project and the HVDC Pole 3 project were approved.

3.12 Each of those investments has now been, or is being, constructed and commissioned.[41]

3.13 As explained further in section 4 of this working paper, the Authority considers that the current TPM was not designed to adapt to changes in the level of and

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40 Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012, page 34, available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c2119.

41 Section 4 of this working paper highlights the impact of those transmission investments in the context of transmission pricing.

need for investment in the transmission network.[42] Further, given the large increase in TPM charges caused by recent investments being commissioned and added to the RAB, the Authority considers that any existing inefficiency within the TPM will be magnified.

3.14 In relation to the changes to the regulatory framework, the Electricity Authority's statutory objective is different from the statutory objective the Electricity Commission had under the Electricity Act 1992. It is appropriate for the Authority to consider whether the TPM, which was approved under the Commission's statutory objective, best promotes the Authority's statutory objective.

Relationship between the material change in circumstances and options the Authority can consider

3.15 In submissions on the October 2012 issues paper, during the May 2013 conference, and in relation to earlier working papers, submitters have questioned whether a material change in circumstances in relation to one aspect of the TPM could justify a wider change to the TPM. That is, some submitters were of the view the Authority can only investigate options that address the issues arising from the material change in circumstances.

3.16 The Authority's view is that the material change in circumstances does not restrict the Authority to proposing changes that address only the issues arising from the material change in circumstances, for the reasons set out below.

3.17 The TPM is part of the Code. Under section 32(1) of the Act, the Code may only contain provisions that are consistent with the Authority's statutory objective and that are necessary or desirable to promote any or all of the matters listed in section 32(1). Those matters repeat aspects of the Authority's statutory objective. In the Code, the requirements of the Act are reflected in clause 12.89 (which requires Transpower to develop a TPM consistent with the Authority's statutory objective) and clause 12.91 (which provides for the Authority to refer a proposed TPM back to Transpower if the TPM does not adequately conform to the requirements of clause 12.89).

3.18 Therefore, once the material change in circumstances threshold is met, the Authority is required by the Act and the Code to consider whether a problem with the TPM exists that necessitates a change to the Code in order to better promote the Authority's statutory objective. Further, in considering potential changes to the Code, the Authority must determine whether amending the Code is necessary or desirable to promote the matters specified in section 32(1). In summary, to meet the requirements of the Act (section 32(1)) and the Code (clause 12.89), the proposal for a change to the Code may include aspects addressing issues other than the issues arising from the material change in circumstances.

3.19 Having said that, the Authority's TPM proposals are directed at addressing the issues arising from the changes that the Authority has identified as constituting a material change of circumstances: allocating a higher Maximum Allowable

[42] Transpower's opening Regulatory Asset Base (RAB) is expected to increase from a value of $2,606.7 million in 2011/12 to an expected value of $4,610.2 million in 2015/16, an increase of 77%. Source: Transpower annual regulatory reports, 2011/12 and 2013/14. The resulting increase in Transpower's MAR has affected the TPM pricing signals.

Revenue (MAR), set under Transpower's individual price-quality path (IPP), taking advantage of better computational power, and ensuring that the Authority's statutory objective (rather than the Electricity Commission's) is given effect.

Use of the Decision-Making and Economic framework

3.20 Some parties submitted that the Authority should abandon the DME framework. Submitters were concerned that the DME framework was being used by the Authority to justify or pre-determine a preferred option, and that the continued use of the DME framework was an unnecessary and unhelpful constraint on the Authority's thinking and process.

3.21 Having considered those submissions, the Authority remains of the view that the DME framework provides a valid basis for assessing which charging options better promote efficiency, and therefore better promote the Authority's objective for transmission pricing. Accordingly, the Authority does not intend to abandon the DME framework.

3.22 The DME framework, therefore, has guided the Authority's selection of options presented in this working paper. This working paper undertakes a qualitative evaluation of options, to help identify whether there is a preferred option or package that provides the greatest net benefit relative to the status quo.

3.23 After considering submissions on this working paper, the Authority will develop a preferred option, consistent with the DME framework, and then assess whether it provides net benefits relative to the status quo, with a quantitative CBA (to the extent possible). The preferred option will also be assessed against each limb of the statutory objective.

The statutory objective and transmission pricing

3.24 One of the Authority's foundation documents is its *Interpretation of the Authority's statutory objective*.

3.25 The DME framework sets out how that interpretation applies in the context of transmission pricing. In particular, the Authority concluded that it should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. Overall efficiency refers to both efficient operation of and efficient investment in the electricity industry – the grid, generation, and on the demand-side.

3.26 This involves facilitating:

(a) efficient investment in the electricity industry through providing incentives so that the right investments occur at the right time, and in the right place. Those investments may be in the transmission grid, generation (including distributed generation), distribution networks or on the demand-side

(b) efficient operation of the transmission grid, generation (including distributed generation), distribution grids and demand-side management. This means providing incentives so that the day-to-day operation of transmission, generation, distribution and demand-side management involves an efficient trade-off between reliability and cost.

3.27 Determining the design of an efficient transmission charge is likely to require a trade-off between static and dynamic efficiency. The *Interpretation* suggests that, where such a trade-off is required, preference should be given to promotion of dynamic efficiency.

3.28 Several submitters suggested that the Authority needs to take account of, and explain the trade-offs between, all of the limbs of the Authority's statutory objective, in particular, the reliability limb.

3.29 The Authority considers that its interpretation of its statutory objective in relation to transmission pricing does take into account the reliability (and competition) limbs of the statutory objective. Having said that, while the Authority has decided to focus on overall efficiency, this does not mean that the Authority will ignore the reliability and competition limbs. The Authority will assess any proposal against each limb of the Authority's statutory objective, to ensure that the Authority's statutory objective is given effect, and to make it clear if or when trade-offs may occur.

Efficient investment, the Authority and the Commerce Commission

3.30 Some submitters considered that the Authority should not use the TPM to encourage efficient grid investment. Submissions included:

(a) that it is for the Commerce Commission to encourage efficient grid investment, not the Authority. The Authority's role under the Code is limited to efficiently allocating the full economic costs of investments in accordance with the Authority's statutory objective. The role of ensuring efficient grid investment is for the Commerce Commission

(b) that a change in the TPM would not incentivise parties to participate more in grid investment processes

(c) that, even if a change in the TPM led to increased participation in grid investment processes, this would not lead to more efficient outcomes.

3.31 The Authority's responses to each of these points are provided below.

Transmission pricing and efficient investment

3.32 Throughout the TPM review, the Authority has received submissions that indicate that the TPM affects both transmission investment and investment in the wider electricity industry. For example, the development and use of load control in the upper South Island in response to the current TPM has clearly played a role in deferring transmission investment.[43]

3.33 The Authority concludes that transmission charges are an important factor among several factors that determine what transmission proposals are considered by Transpower and ultimately brought to the Commerce Commission for its approval. Given the Authority's statutory objective and its responsibility for the TPM, the Authority must therefore ensure that the TPM is promoting efficient investment in the electricity industry.

Influence of TPM on participation in the grid approval process

3.34 The Authority considers that improved targeting of TPM charges to the parties that create either the need for or benefit from transmission investments would

[43] Orion, Submission on TPM: Problem Definition, 28 October 2014, page 10.

improve incentives to participate in the grid approval process. However, submitters on the working papers had varying views on the question of improved participation.

3.35 The Authority acknowledges the current scepticism of some parties in relation to the scope for improved participation in the investment process by changing the TPM so that transmission charges are more targeted. The Authority considers that parties are familiar with current arrangements where interconnection costs are shared by all interconnection customers. This reduces the incentives for active participation as costs are diluted among numerous parties, many of whom have little understanding of the transmission investment in question, or the area in which it is located. The Authority considers that it is intuitive that if charges for an investment apply to parties who would not have their demand met without the investment, parties would be better incentivised to efficiently and effectively scrutinise proposed investments.

Increased participation in the investment approval process leading to investment efficiency

3.36 Many submitters were of the view that, even if a change to the TPM led to increased participation in the grid investment process, this would not lead to more efficient investment in the grid.

3.37 The Authority considers that increased participation in the investment approval process will enhance the operation of the Commerce Commission regime because that regime anticipates that interested participants will assist the Commerce Commission to scrutinise Transpower’s proposals. The Authority’s discussions with the Commission support this conclusion.

3.38 Transmission investments are highly complex, and scrutiny of transmission investments requires specialist knowledge and access to detailed, difficult to access, and sometimes confidential, information. Due to the information asymmetry problem[44] the regulator inevitably knows less about an entity that it regulates than the entity itself knows. This problem is particularly acute in complex industries where information is of a technical nature.

3.39 In the problem definition working paper, the Authority suggested that certain transmission customers have specialist knowledge in regard to transmission investments (and, in fact, are practiced in developing non-transmission alternatives), have access to detailed information, and understand the uncertainties surrounding these investments. Some submissions disagreed that this was the case. Having had regard to those submissions, the Authority has not changed its view. When those transmission customers are faced with the cost of Transpower's investments, as long as their share of the costs is sufficiently material, transmission customers will have incentives to provide comprehensive scrutiny of those proposed investments and reveal their true

[44] The information asymmetry problem is that regulators are likely to have less knowledge about the entities they regulate than the entities know about themselves, the circumstances they face and their industry. As a result of this information asymmetry, an entity requiring approval for an investment by a regulator has the ability to amplify the need for a particular investment, overstate the benefits and understate the costs, dismiss alternatives to its preferred investment, etc. For further discussion on this see pages 44-45 of the problem definition working paper.

preferences. They will also be incentivised to carefully consider non-transmission alternatives.

3.40 The Authority notes that the Commerce Commission currently identifies who benefits from investments as part of its assessment process. While the Commerce Commission makes decisions without regard to allocation of costs, further alignment of the TPM to the grid investment process will better incentivise participants to make submissions that assist the Commerce Commission to make efficient decisions. For example, a participant's view on the level of benefits it receives from a proposed investment may differ to that of Transpower or to that of the Commerce Commission. The participant does not need to have market power to lobby or influence the Commerce Commission. The participant would simply put forward its alternative case for the Commerce Commission's consideration.

Detail of options and specificity of guidelines

3.41 Several parties submitted that the Authority's proposal in the October 2012 issues paper and the options in the beneficiaries-pay working paper went beyond the scope of the Authority's role under the Code of determining guidelines for Transpower to develop the TPM.

3.42 This issue is relevant to this working paper because it affects the level of detail to which the options are developed by the Authority, as explained below.

3.43 The issue of the level of detail to which the options are developed, and specificity of future guidelines, must be considered in light of the requirements of the Act and the Code. The Authority can amend the Code only to include provisions that are consistent with the Authority's statutory objective and which are necessary or desirable to promote any or all of the matters specified in section 32(1) of the Act.

3.44 The requirements of the Act are reflected in the fact that the Authority may either refer the TPM back to Transpower or amend the TPM or both if the Authority is of the view that the TPM does not adequately conform to one of the requirements of clause 12.89(1).[45] One of those requirements is that the TPM is consistent with the Authority's statutory objective. That means that the Authority is ultimately responsible for the content of the TPM.

3.45 Therefore, interpreting the Authority's powers as requiring the guidelines to be very high level would be inconsistent with the fact that the Authority is ultimately responsible for the content of the TPM.

3.46 In summary, the Authority is of the view that it must publish guidelines at the level of specificity that is necessary to clearly express what it requires from the TPM in order to meet the requirements of the Act and the Code.[46] This means that the options discussed in the consultation process are also discussed with a high level of detail, in order to assist the Authority to produce the guidelines.

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45 See clause 12.91 of the Code.

46 By way of example, the existing guidelines include the very specific requirement for South Island generators to bear the cost of the HVDC link.

Transpower's TPM operational review

3.47 Transpower undertook a TPM operational review in 2014/15, in parallel with the Authority's TPM review, and in February 2015 submitted a proposed variation to the TPM. The proposed variation initially comprised five components. In March 2015, Transpower added two further components.[47,48]

3.48 In preparing this options working paper, the Authority has taken into account the material prepared by Transpower as part of Transpower's operational review. However, it is important to keep in mind that Transpower's operational review focuses mainly on operational efficiency of the current TPM within the existing guidelines, and is aimed at determining whether there is opportunity for "fine-tuning" the TPM within those guidelines. In contrast, the Authority's review focuses on overall efficiency, and contemplates new guidelines being published.

3.49 Transpower's operational review is, therefore, narrower in scope than the Authority's.

3.50 Nevertheless, Transpower's operational review complements the Authority's TPM review. For example, Transpower's operational review has highlighted changes to investment and operation since the TPM was made, and identified several substantial problems with the TPM.

3.51 The Authority has consulted on or is consulting on, some of the components of Transpower's proposed variation to the TPM. The purpose of that consultation is to determine whether the components would better promote the Authority's statutory objective, and should be implemented by amending the TPM in Schedule 12.4 of the Code.

3.52 The Authority anticipates decisions on Transpower's proposed variation to the TPM may be made before the release of the second issues paper. If any or all components of the proposal are implemented, the second issues paper would include the revised counterfactual in the analysis.

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47 Details of the Transpower TPM Operational Review are available at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transpower-tpm-operational-review/development/operational-review-proposal-documents.

48 Two components were subsequently withdrawn. The Authority has consulted on four components, and is, as at the date of this paper, consulting on the other remaining component.

4 Summary of the Authority's current views on problem definition

4.1 The Authority appreciates the submissions it has received on the problem definition, including in response to its September 2014 problem definition working paper.

4.2 To assist interested parties to respond to this working paper, the Authority outlines below a preliminary set of updated views on problems with the current TPM. The Authority considers that problems with the current TPM fit broadly into four categories:

(a) it is not adaptive and sends the wrong price signals

(b) it does not appear to be cost-reflective

(c) it fails to support the discovery of efficient transmission investment through the transmission investment approval process, and

(d) it may not be durable.

4.3 These problems are discussed in greater detail below.

It is not adaptive and sends the wrong price signals

4.4 The current TPM has not adapted well to recent transmission investment. This is seen by the increase in the strength of the HVDC and interconnection charge pricing signals after substantial transmission investment. For example, as noted by Transpower:

(a) "A combination of capacity expansion investments and flat demand growth has led to an increase in the interconnection rate (ICR) of more than 60% from $68 per kW in 2008/09 to $114.47 per kW in 2014/15 (both in 2014/15 dollars)"[49]

(b) "A combination of the costs associated with the HVDC upgrade, and a reduction in the level of South Island generation attracting the HAMI charge has resulted in an increase of approximately 60% in the HVDC rate from $27 per kW in 2008 to $44.60 per kW (in 2014/15 dollars)".[50]

4.5 The failure of the current TPM to adapt to recent transmission investment is exacerbated by the pricing signals strengthening after transmission investment is made.

4.6 From a (dynamic) efficiency perspective the pricing signal should strengthen before the investment is made. If the pricing signal does not strengthen before an investment, users will continue to use the transmission network even when it is congested, bringing forward the need for transmission investment.

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49 Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4.3.1, page 16. Note, the Authority calculates the increase at 68%.

50 Refer to Transpower, Attachment B: Background and Supporting Information, 13 February 2015, section 4.3.2, page 16. Note, the Authority calculates the increase at 65%.

4.7 The strengthening of the signal after the investment is made, as has occurred, sends a statically inefficient price signal to not use a new asset even though spare transmission capacity is at its highest.[51] The current TPM, accordingly, is resulting in both static and dynamic inefficiencies.

4.8 The Authority considers that the problems with the HVDC and interconnection charges have been well documented by both the Authority, throughout this review, and by Transpower in its TPM operational review.

4.9 The Transpower TPM operational review relied on the Authority's quantitative analysis in the problem definition working paper,[52] with Transpower noting "We consider that the analysis of RCPD and HAMI charges in the Authority's TPM problem definition working paper is broadly sound … and have used it as an input to our own review".[53]

4.10 Examples of the problems with the current TPM's pricing signals include:

(a) The HAMI allocation of the HVDC charge can cause inefficient withholding of South Island grid-connected generation capacity (static inefficiency). The problem definition working paper estimated the resulting inefficiency at $12 million present value.[54]

(b) The HVDC charge can discourage investment in South Island grid-connected generation (dynamic inefficiency). The problem definition working paper discussed the resulting inefficiency and noted that TPAG had previously estimated it at $24 million +/- $9 million (present value), but concluded that the true inefficiency probably lies at or below the bottom end of that range.

(c) The HVDC charge also sends a somewhat crude South Island versus North Island signal that fails to distinguish between different parts of the South Island (dynamic inefficiency), that is, it fails to recognise that investment in generation in the USI could result in lower transmission investment needs than generation investment in the LSI or some parts of the North Island.[55]

(d) The problem definition working paper identified that the interconnection charge may over-signal:

(i) the need for load shedding at peak times (static inefficiency)

(ii) the need for overall reductions in consumption (static inefficiency)

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51 This is not to suggest that dynamic efficiency cannot be promoted through altering the charges of existing assets. For example, the Authority considers that reallocating HVDC charges could promote investment efficiency in generation, leading to downward pressure on wholesale prices.

52 Refer, in particular, to Transpower's consultation paper: 2014/15 TPM operational review: second consultation paper, 13 November 2014.

53 Transpower, 2014/15 TPM operational review: second consultation paper, 13 November 2014, page 7.

54 Transpower also estimated the scale of this inefficiency, in the course of its operational review of the TPM, and produced a higher estimate. See https://www.ea.govt.nz/dmsdocument/19325, which sets out Transpower's range of estimates of the inefficiency – from $6.1 million to $11.3 million *per year*.

55 Transpower has agreed to investigate this problem as part of its operational review of the TPM (http://www.ea.govt.nz/dmsdocument/19371).

(iii) the cost of increasing NZAS production in summer (static inefficiency)

The resulting inefficiencies may exceed $100 million present value.[56]

It does not appear to be cost reflective

4.11 The Authority has concerns about how cost-reflective the TPM is and is concerned that the TPM is becoming increasingly less cost-reflective over time.

4.12 Prices are cost-reflective and signal the economic costs of service provision, by:[57]

(a) being subsidy free (equal to or greater than incremental costs, and less than or equal to stand-alone costs)[58]

(b) having regard, to the extent practicable, to the level of available service capacity, and

(c) signalling, to the extent practicable, the impact of additional usage on future investment costs. (As a corollary, any increase in the charges should be in line with increases in the incremental cost of supply.)

4.13 A TPM that is not cost-reflective results in users of transmission services not facing charges that reflect the cost of their usage. This means that their own decisions around operation and investment are based on inaccurate information about costs, which undermines efficiency.

4.14 The Authority considers that the current TPM gives rise to several potentially substantive cost-reflectivity issues, including:

(a) The postage stamp interconnection charge means transmission investments to serve particular regions or areas are paid by consumers across New Zealand rather than just by consumers receiving the service.

(b) Four of the largest post-2004 transmission upgrades: NIGU[59], NAaN, Otahuhu GIS, and UNI reactive support were principally undertaken to provide transmission services to UNI customers. Only a (comparatively) small amount of transmission investment has been undertaken for other regions.

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56 Transpower also identified inefficiencies arising from the RCPD allocation, in the course of its operational review of the TPM. See http://www.ea.govt.nz/dmsdocument/19117, http://www.ea.govt.nz/dmsdocument/19282, http://www.ea.govt.nz/dmsdocument/19283.

57 Electricity Commission, Distribution Pricing Principles and Information Disclosure Guidelines, February 2010, Pricing Principles, (a)(i) – (iii).

58 There is a wide range of prices that would be between incremental and stand-alone cost given the high proportion of common costs associated with the transmission grid.

59 As noted in the Beneficiaries-pay working paper (paragraph 8.13): “the primary justification for the NIGU project was improved reliability in the upper North Island region; if the project did not promote this objective it would not have proceeded.”

(c) More than $1.3 billion[60] of transmission investment has been made in the UNI since 2004.[61] This accounts for 29 percent of Transpower's RAB of $4.61 billion in 2015/16, or 48 percent of approved transmission investment (including HVDC) since 2004.

The investment translates to an increase in Transpower's revenue requirement of $221 million per annum.[62] Of this, only $87 million or 39 percent is paid for through an increase in charges to UNI. Transmission prices in the LNI, USI and LSI have increased by 61 percent, on average, largely to pay for the cost of investment in the UNI, and to service Auckland, in particular.

The relationship between investment in different regions and transmission charges is illustrated in Table 3 below.

Table 3: Incidence and allocation of post-2004 approved investment[63]

Region	Post-2004 investment*	Impact on Transpower revenue requirement	Actual increase in interconnection charges from 2008/9 to 2015/16	Actual tariff increase as a % of impact on revenue requirement
UNI	$1,342M	$221M	$87M	39%
LNI	$237M	$40M	$80M	200%
USI	$77M	$14M	$40M	283%
LSI	$81M	$39M	$40M	102%

*does not include HVDC or connection investment

(d) Transpower has assessed that the difference between interconnection charges in the North and South Island relative to asset value is growing, with the split in book value of transmission assets in the North and South Island going from 60:40 in 2007 to 79:21 in 2014.[64]

Transpower has noted that "Current allocations to between the North Island and South Island, under the RCPD charge, are 66% and 34%

60 Transpower provided the Authority with a spreadsheet detailing recent major investments. The Authority arrived at $1.3 billion by calculating the lower of the approved amount and actual spend for UNI investments.

61 This does not include investments such as the Wairakei Ring as, while the investment was made in part to serve UNI demand for transmission services, the assets are not in the UNI. The North Island grid upgrade was included as a UNI investment because this investment was driven by UNI demand. Note that to arrive at this number the Authority took the lower of the approved amount and actual cost for each investment.

62 For this purpose, the impact of investments on Transpower's revenue requirement is assumed to be 15% of the cost of the investment per annum. This is an approximation. It accounts for operating expenses and depreciation in relation to investments. Refer Appendix A, A.40, for a further explanation of the assumption.

63 Post-2004 investment is based on actual major capex spend from Transpower's published RT06 file.

64 E-mail from Transpower, 28 May 2015.

respectively.[65] We have compared the current allocation of interconnection charges to each Island to the book value of the grid in each Island. On this analysis we estimate the book value of the North Island grid represents 79% of interconnection assets and the South Island 21%. We have also compared the allocation of interconnection charges to each Island to the estimated replacement cost of the grid in each Island. On this analysis we estimate the estimated replacement cost of the North Island grid represents 73% of interconnection assets and the South Island 27%."[66]

On its face, this analysis suggests that interconnection charges are relatively high for load in the South Island, and relatively low for load in the North Island, under postage stamp pricing.

(e) The projections for regional development and population growth in Auckland versus the rest of the country suggest the imbalance identified above could continue, and worsen, over the medium to long-term.

(f) While the Authority acknowledges Vector's point that "Under the present postage stamp pricing there is at least a degree of electricity distribution businesses (EDBs) cross-subsidising each other" and that "To some degree the cross-subsidisation cancels itself out",[67] the above evidence indicates there is a clear imbalance that does not cancel out, and is growing.

(g) The Authority does not consider it efficient for other regions to subsidise growth in a growing region like Auckland (the UNI region transmission charges increasing by less than the cost of transmission investment driven by UNI demand). The impact on transmission pricing for other regions has already been substantial. Subsidisation artificially stimulates greater growth and investment in growing regions, putting further pressure on infrastructure and stimulating greater investment requirements, at the expense of other regions.

(h) Power from North Island generators is sometimes transferred across the HVDC when South Island hydro lakes are at low levels. North Island generators pay nothing for using the HVDC to send their power south.

(i) Electricity generators use the grid (both interconnection and HVDC) to transport electricity they generate to users. The choice of generation location has substantial implications for the configuration of the grid/transmission investment requirements – as illustrated by the need for Pole 2 and Pole 3 because there is over-capacity in electricity generation in the South Island and under-capacity in the North Island.

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65 The allocation of interconnection charges was 65% and 35% for the North Island and South Island respectively in the 2008/9 pricing year and remained effectively unchanged at 66% and 34% respectively for the 2014/15 pricing year.

66 Transpower, Proposal to amend the Electricity Industry Participation Code 2010, TPM Operational Review: NZAS Summer Load Limit, 13 February 2015, footnote 9, page 5.

67 Vector, Submission to the Electricity Authority on Transmission Pricing Methodology: Issues and proposals, 1 March 2014, paragraph 67.

(j) Some grid-connected industrial consumers in the North Island pay little for interconnection services because they alter their demand patterns to minimise their contribution to RCPD. For example, some direct connect customers have been able to largely or fully avoid interconnection charges.[68]

(k) Where connection to the grid results in specific costs to the individual load customer, they will incur the cost of this connection. If, however, connection to the grid results in increases in costs (which may occur over time) in parts of the grid used by multiple load customers, then those costs are subsidised through postage stamp pricing, smearing the costs over all load.

It fails to support the discovery of efficient transmission investment through the transmission investment approval process

4.15 The Authority considers that transmission charges have an important role to play in promoting efficient investment by supporting the discovery of efficient transmission investments.

4.16 Under the current charging arrangements for HVDC and interconnection assets some customers pay considerably more than the cost of providing them with transmission services while others pay considerably less.[69] Some parties pay nothing or almost nothing for certain transmission services even though they clearly use those services.

4.17 Since the current postage stamp interconnection charge smears costs over all load, the incentives of load parties that would benefit from any particular investment to scrutinise whether the investment is necessary or efficient may be weak. Incentives may be non-existent for generators in the case of interconnection investment, since they don't face interconnection charges, and minimal in the case of some large loads that are able to largely avoid the interconnection charge. Likewise, the incentive to scrutinise HVDC investments may be non-existent in the case of loads and North Island generators who do not face the HVDC charge.[70]

4.18 By contrast, the incentive for scrutiny is relatively strong in relation to connection charges, which may be one reason a number of connection investments are subject to customer investment contracts (CICs).

4.19 The Authority considers the failure of the current TPM to allocate charges in a manner that adequately reflects the cost of providing transmission services to each transmission customer creates inefficient investment incentives. This is because the parties (and regions) receiving the additional grid services may have incentives to promote transmission investments in their area even when the full economic costs exceed the economic benefits likely to be delivered, potentially encouraging more transmission capacity than is economic. The

[68] Refer to Appendix E: Breakdown of the incidence of charges.

[69] Or, in terms of incremental and stand-alone cost, the implicit mark-up on incremental cost or contribution to common costs will vary substantially from customer to customer (and region to region).

[70] Inefficient investment in the HVDC link would actually improve the competitiveness of North Island generators relative to South Island generators, as South Island generators would incur additional costs that North Island generators do not bear.

allocation of charges under the current TPM also creates incentives for local distribution networks (paid by the local population) to pursue transmission interconnection investment (paid by the entire population) even when the latter is less efficient than distribution investment.

4.20 Logically, the more a particular individual is affected by a decision, the greater the interest they will have in that decision and the greater the incentive to engage in the decision-making process. This often gives rise to very strong local opposition to large development projects, such as major roads and transmission and generation projects.

4.21 Where the costs and benefits of a decision are more widely dispersed the incentives to engage will typically be weaker.

4.22 This is part of the reason why the Authority considers postage stamp pricing results in lower engagement than would otherwise be the case in the Commerce Commission's transmission investment approval process.

It may not be durable

4.23 The Authority also acknowledges the current TPM has been in place for 7 years. However, issues such as HVDC pricing have been extremely controversial and the current TPM has been under review for most of its existence.[71]

4.24 The Authority is also concerned problems with the TPM – in particular, the divergence between costs and prices under postage stamp pricing – are likely to continue to grow over time given the imbalance of economic and population growth between regions such as Auckland versus the rest of the country. This increases the likelihood of lobbying for change to the TPM. This creates uncertainty, which undermines efficient investment. In addition, the substantial costs involved harm efficient operation.

4.25 Some durability issues might be able to be dealt with through Transpower undertaking periodic operational reviews of the TPM (such as the 2014/15 TPM operational review).

4.26 However, it is unlikely to be feasible to develop mechanistic rules for determining when and how the TPM would be reviewed and how the pricing

[71] The current TPM has applied place since 1 April 2008.

The Electricity Commission commenced a review of the TPM in February 2009 in response to requests by South Island generators.

The Commission undertook analysis of issues and options for transmission pricing and twice consulted with participants and consumers in October 2009 and July 2010.

Following the establishment of the Authority on 1 November 2010, the Authority continued the review.

In January 2011, the Authority Board established a Transmission Pricing Advisory Group (TPAG), consisting of electricity industry participant representatives and customers, to provide advice and recommendations on a preferred option for transmission pricing.

TPAG was unable to reach a consensus on key aspects of the current TPM, such as charging for the HVDC link and so did not make firm recommendations on these aspects.

TPAG presented its analysis to the Board in early September 2011.

Since then, the Authority has been reviewing the TPM, starting with the development of the DME framework.

signals should change. This could result in potential for inefficient delay in changes to the TPM. It also creates uncertainty for investors in long-life assets such as distributed generation/generation as investors will not know whether the TPM pricing signals will remain intact. This uncertainty could weaken the effectiveness of any TPM pricing signals (regardless of how efficient/correct the pricing signals are).

4.27 In addition, TPM reviews under clause 12.85 of the Code are limited by the TPM guidelines, so there may be situations where Transpower could not recommend the optimal changes to the TPM because they would not be consistent with the guidelines.

Additional observations in relation to the problem definition

4.28 The Authority makes the following additional observations in relation to the problem definition:

(a) Connection charges do not appear to be fully cost-reflective because the asset charge component is based on average depreciation for all connection pool assets and the operating expense allocation is calculated using broad allocators rather than actual cost. However, the implementation costs of moving to Depreciated Replacement Cost (DRC)-based charging for the asset charge and an actual cost-based methodology for allocating operating expenses are likely to be high. The Authority is still considering whether there would be efficiency gains from moving to DRC-based charging, but is not proposing changes at this stage. The Authority will consult on this as part of the second issues paper if it decides that a change may be desirable.

(b) There is a free-rider problem in relation to static reactive investments. This is because parties that exacerbate the need for static reactive investments by Transpower do not face the full cost of those investments. Consequently, they lack the right incentives to make efficient decisions on investing in equipment that avoids the need for static reactive investment, for example, large motors, or investing in static reactive equipment themselves.

(c) The Authority considers that the prudent discount policy (PDP) under the existing TPM could be improved. The Authority acknowledges the PDP is a useful mechanism for addressing the fact that some customers' demand for transmission services is very sensitive to transmission charges (that is, their price elasticity of demand for transmission services is high). However, The PDP addresses only a subset of situations where customers may take actions to reduce their transmission charges that may be privately beneficial but not beneficial to the economy as a whole. The Authority considers that the future requirement for a PDP will depend on the nature of the TPM that is decided on. Accordingly, the Authority will assess the need for and nature of the PDP in the second issues paper in the context of the options it considers.

5 Selection of options

5.1 The Authority has consulted on, or considered, a wide range of options for potential reform of the TPM including, but not limited to:

(a) the TPAG recommendations

(b) the original beneficiaries-pay SPD charge proposal included in the October 2012 issues paper[72], and amended versions of the original SPD charge proposal

(c) various beneficiaries-pay options, including Grid Investment Test (GIT)-based, flow tracing, and further versions of the SPD charge

(d) LRMC options including tilted postage stamp, and

(e) other options put forward by submitters.

5.2 The options the Authority is now considering are set out in Table 4 and consist of:

(a) a **Base Option,** which is common to all the options: This option focuses on recovering revenue through a deeper connection charge and an AoB charge. Specifically, the Base Option includes a revised approach to crediting LCE, the existing connection charge, a deeper connection charge, a kvar charge, an AoB charge, and a postage stamp (flat rate) capacity-based residual charge on load

(b) the **Base Option + LRMC**: the Base Option combined with LRMC

(c) the **Base Option + SPD**: the Base Option combined with SPD beneficiaries-pay.

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72 Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012.

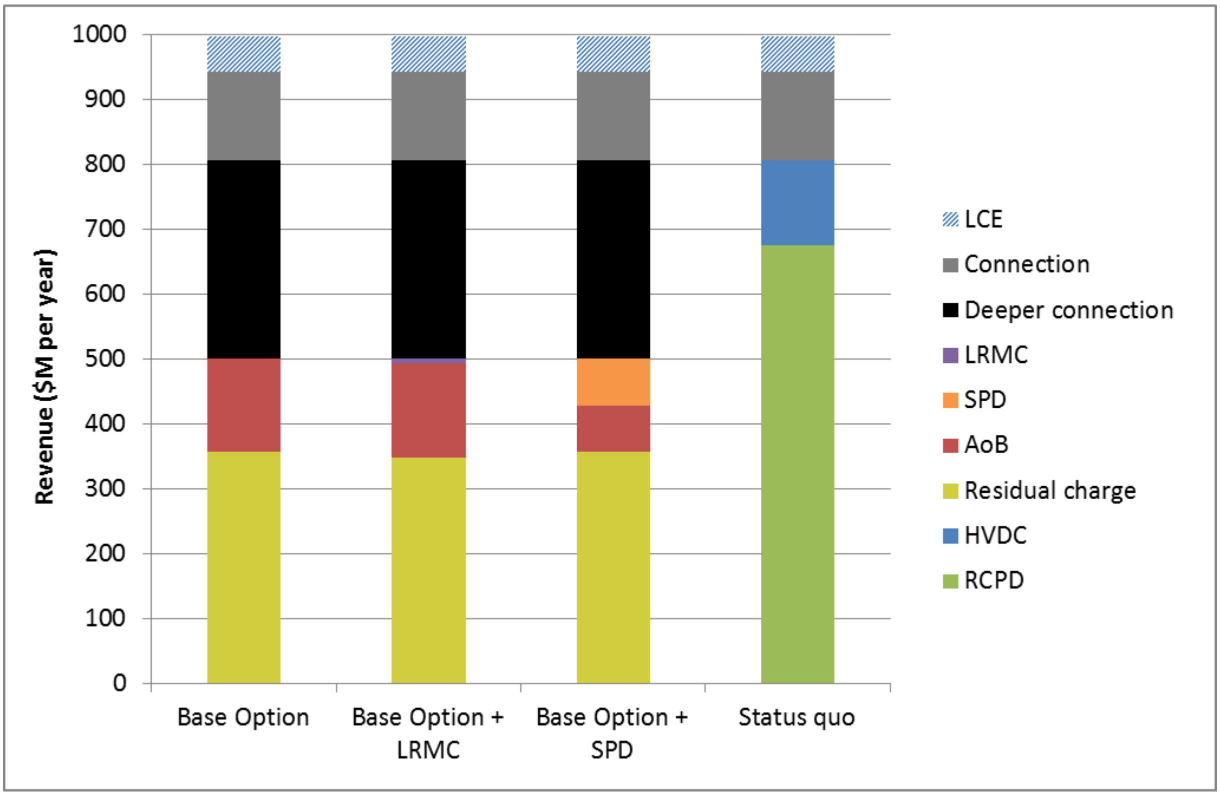
Table 4: TPM options

<table>
<tr><th>Asset cost</th><th>Base Option</th><th>Base Option + LRMC</th><th>Base Option + SPD</th><th>Status Quo TPM</th></tr>
<tr><td>All assets</td><td colspan="3">LCE crediting against charges for certain assets, then against remaining revenue requirement</td><td>LCE credit against charges in proportion to charge share</td></tr>
<tr><td>Connection asset costs</td><td colspan="3">The current connection charge (all options)</td><td>Connection charge</td></tr>
<tr><td rowspan="5">HVDC and Interconnection costs</td><td colspan="3">Deeper connection charge (all options)</td><td>Interconnection charge (RCPD)</td></tr>
<tr><td></td><td>LRMC charge (future investments)</td><td>SPD charge</td><td rowspan="4">Interconnection charge (RCPD)

HVDC charge (HAMI)</td></tr>
<tr><td colspan="3">kvar charge for static reactive support equipment (all options)</td></tr>
<tr><td colspan="3">AoB charge (all options)</td></tr>
<tr><td colspan="3">Capacity-based residual charge (all options)</td></tr>
</table>

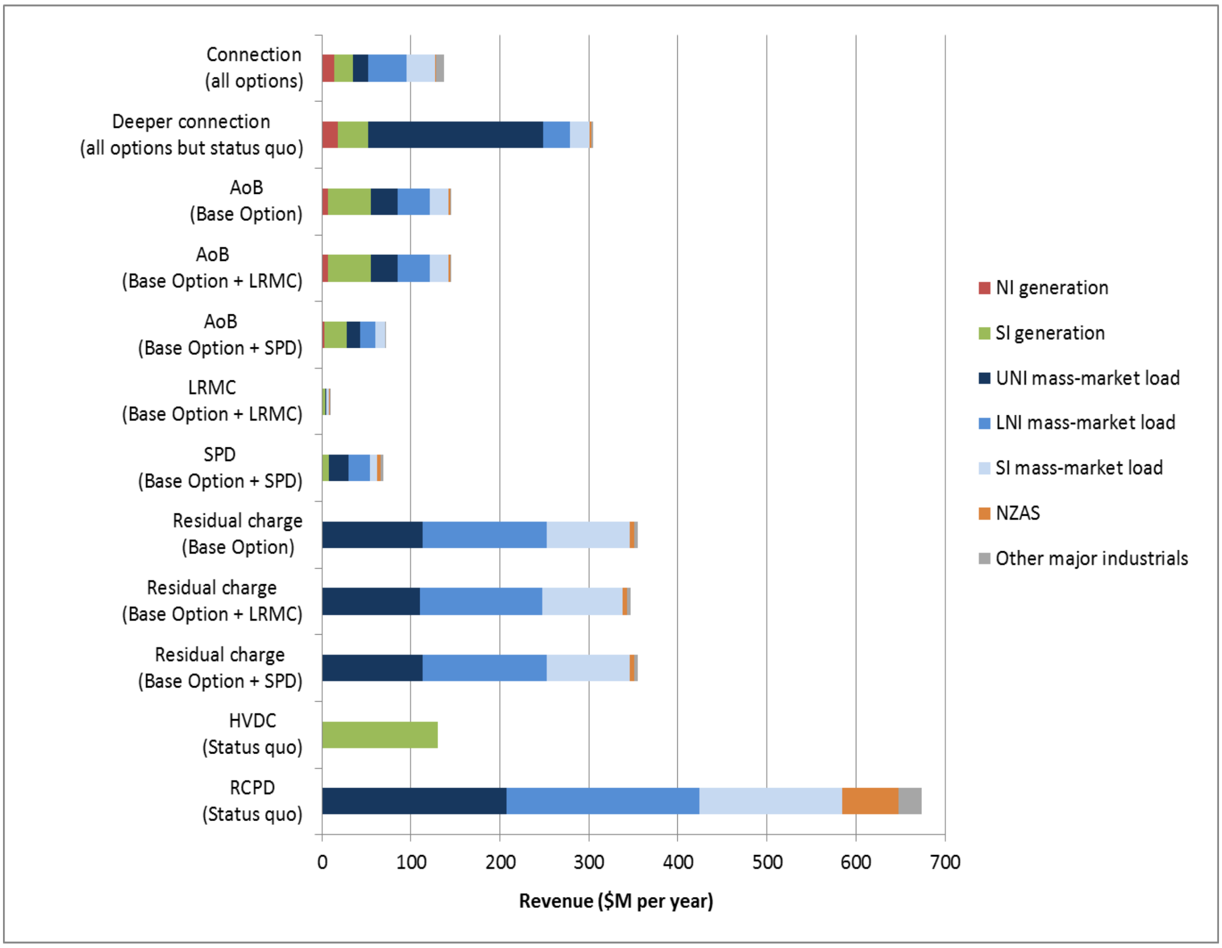
5.3 Figure 3 provides a modelled breakdown of revenue for each option by the type of charge. Note that revenue (in $M per year) is based on a hypothetical scenario covering the 2017-2019 years. All of the Authority's options include a kvar charge for recovering the costs of static reactive support. The kvar charge has not been included in the modelling because, based on its most recent estimates of power factors which showed power factors are close to parity, the Authority expects income from the kvar charge would be minimal.

Figure 3: Breakdown of options by charge



5.4 Figure 4 shows how each of the charges is distributed across groups of parties.

Figure 4: Distribution of charges across parties in the simulated scenario



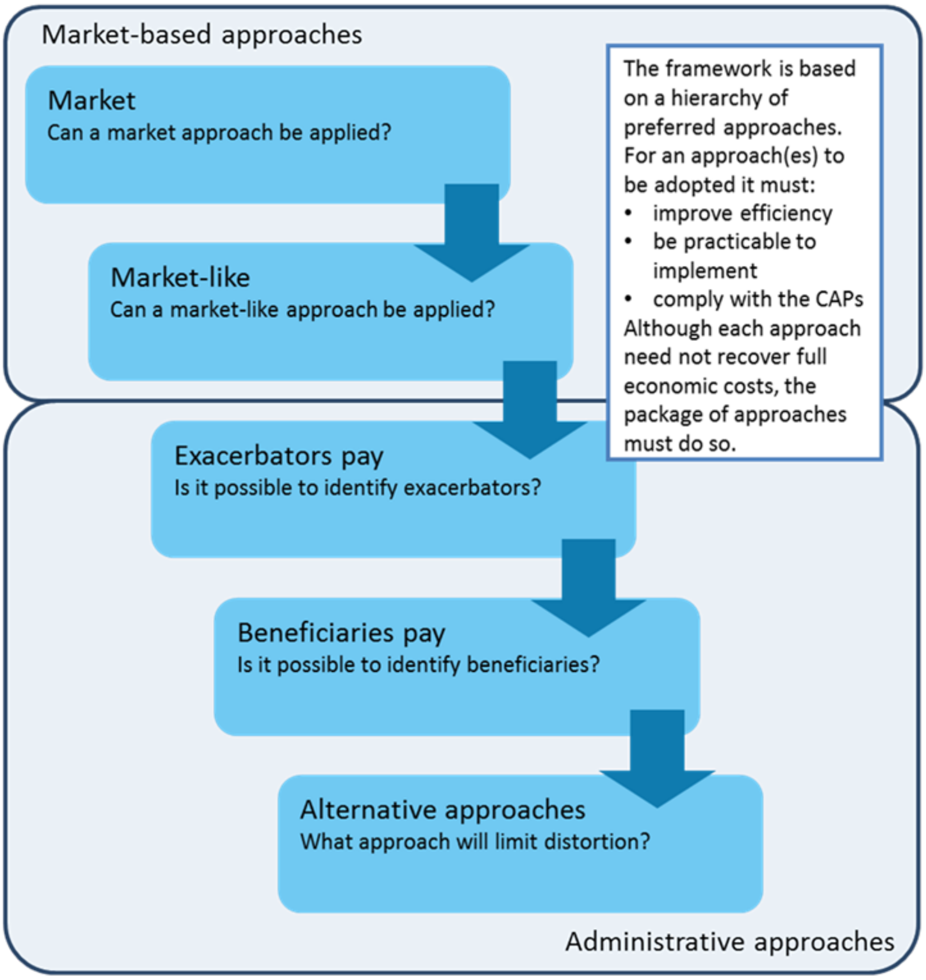
Note: This graph excludes crediting of LCE and the kvar charge.

How the DME framework was applied to select the options

5.5 The selection of TPM options is guided by the Authority's DME framework, as set out in Figure 5.[73]

[73] For further details on the DME framework, see Decision-making and economic framework for transmission pricing methodology: decisions and reasons, 7 May 2012, available at: http://www.ea.govt.nz/dmsdocument/12978.

Figure 5: Decision-Making and Economic framework for transmission pricing



5.6 The Authority's first preference is for the TPM to apply a market-based approach for determining charges. A market-based approach should result in charges established through the interaction of willing buyers and willing sellers in a workably competitive market (that is, a market approach), or charges that are likely to mimic or replicate the pricing outcomes achieved by a workably competitive market (that is, market-like).

5.7 The combination of options the Authority has developed places emphasis on recovering costs through a market or market-like charge, where possible: deeper connection charges for all three options and LRMC charges for costs deeper in the grid in the case of the Base Option + LRMC.

5.8 The deeper connection charge seeks to replicate charges that would result through negotiation, that is, it is market-like.

5.9 For assets not covered by the deeper connection charge, the DME framework suggests that a market-like approach, such as an LRMC charge, would be preferred.

5.10 The Authority considers that an administrative approach to charging should be preferred when a market-based approach is inefficient or impractical or does not fully recover the economic costs of transmission services.

5.11 The DME framework suggests that, if costs arise as a result of externalities, then exacerbators-pay charging is the next preferred option. If the costs are not the result of externalities, then beneficiaries-pay charging should be preferred.

5.12 The Authority has chosen a combination of charging options that provides the ability to compare using an LRMC charge to promote efficient investment beyond the boundary of the deeper connection charge with relying on beneficiaries-pay charges alone (AoB only under Base Option, and both the AoB and SPD charges under Base Option + SPD).

5.13 The Authority initially considered applying the LRMC charge more broadly, so that it would apply beyond the boundary of the connection charge, that is, it would cover investments proposed to be covered by the deeper connection charge. However, the Authority decided not to develop this option further. The Authority considered the deeper connection charge was the most efficient means of recovering the costs covered by this charge and, therefore, the addition of an LRMC charge was not necessary in relation to these costs.

5.14 The Code prevents the costs of a specific investment being pre-funded.[74] An LRMC charge would therefore be insufficient by itself to recover all of the costs of an investment because it would not recover costs incurred after the period for which the charges are being paid. Therefore another charge would be required to recover the costs of the investments about which the LRMC charge has provided a price signal. However, the Code does not prevent recovery of investment costs incurred by Transpower with a method that allocates those costs based on the costs of future investments, as would be the case with an LRMC charge.

5.15 The inclusion of both exacerbators-pay and beneficiaries-pay charges under each of the options is consistent with Treasury's Guidelines on charging for public services.[75] The charging approaches identified in the Treasury guidelines have been successfully applied in other sectors, for example, civil aviation and air traffic control, where beneficiaries-pay charges are applied and where (the Authority understands) they are generally accepted.

5.16 Where costs remain that are not recovered by more preferred charging approaches, the DME framework provides that these costs should be recovered through an alternative charging approach that limits distortions.

5.17 Since the more preferred charges are designed to promote efficient investment in the electricity industry, the design of the residual charge should focus on minimising distortions to efficient operation. In theory, the best method for doing this is a Ramsey charge, which would impose charges on transmission customers inversely proportional to their price elasticity of demand[76]. However, the Authority does not consider it possible to obtain reliable estimates of the long-run price elasticity of demand for transmission services across all sub-groups and over time. Accordingly, the Authority does not consider that a Ramsey charge is practicable.

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74 The Code specifies that the TPM relates to the allocation of the recovery of costs incurred by Transpower (clause 12.77). This means that the TPM cannot be used to "pre-fund" investment costs that have yet to be incurred.

75 The Treasury, *Guidelines for setting charges in the public sector,* December 2002.

76 A customer's price elasticity of demand is the degree to which their demand for a good or service (in this case, transmission services) is sensitive to a change in price.

5.18 The Authority is, therefore, proposing a postage stamp (flat rate) capacity-based residual charge for all three options.

5.19 The options the Authority is considering in this working paper and the relationship of the charges to the DME framework are set out in Table 5.

5.20 The Authority welcomes comments on whether alternative options or variations on the packages should be preferred or considered. As the Authority intends to be guided by the DME framework when it selects options, suggestions for alternatives should be consistent with the DME framework.

Table 5: **Options and the DME framework**

DME framework		**Base Option**	**Base Option + LRMC**	**Base Option + SPD**
Market	LCE credit	✓	✓	✓
Market-like	The existing connection charge	✓	✓	✓
	Deeper connection charge	✓	✓	✓
	LRMC charge		✓	
Exacerbators-pay	kvar charge	✓	✓	✓
Beneficiaries-pay	AoB charge	✓	✓	✓
	SPD charge			✓
Alternative approaches	Capacity-based residual charge	✓	✓	✓

6 Base Option: Deeper connection + area-of-benefit

Description of option

6.1 The Base Option is common to all three of the options the Authority is considering.

6.2 As Table 4 shows, the Base Option consists of six components:

(a) LCE credit

(b) the existing connection charge

(c) a deeper connection charge

(d) a kvar charge

(e) an AoB beneficiaries-pay charge on post 2004 investments not covered by the above (and possibly Pole 2), and

(f) a residual charge – postage stamp (flat rate) capacity-based charge on load.

6.3 The rationale for these components is the same for all options so is only discussed in relation to this option.

a) LCE credit

6.4 Consistent with the LCE working paper, the Authority is proposing to apply an LCE[77] credit against transmission charges as follows:

(a) LCE attributable to an individual connection asset or deeper connection asset would be credited against the charges of customers that pay for that asset

(b) LCE not attributable to connection or deeper connection assets would be credited in bulk against Transpower's remaining recoverable revenue..[78]

6.5 At present, transmission prices are determined based on a capacity measurement period that is the 12 month period ending 31 August immediately before the start of a pricing year. Transpower typically publishes prices for a pricing year in the December preceding the pricing year.

6.6 Part D of the Benchmark Agreement requires that Transpower calculate a customer's share of LCE every month in accordance with its "prevailing methodology", and issue the customer a credit note for the customer's share as a deduction from the grid charges payable by the customer.

6.7 The Authority considers it appropriate for LCE to be allocated as it arises, and applied as a credit note under the Benchmark Agreement on a monthly basis, as is currently the case. This should not cause problems for EDBs' compliance with Part 4 of the Commerce Act provided they treat any credit notes for LCE on the same basis as any LCE they currently receive.

6.8 The Code would need to be amended to set out a new methodology for allocating LCE to each customer. The Code would also need to deem that the methodology

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77 In the paragraphs that follow "LCE" should be read as including the surplus funds that remain after settlement of FTRs, as appropriate.

78 Further details of the Authority's LCE proposals are contained in Appendix B: Treatment of LCE.

for allocating LCE in the Code is the prevailing methodology under Part D of the Benchmark Agreement.

6.9 Part D of the Benchmark Agreement does not currently provide for LCE to be incorporated into TPM charges.

6.10 At this stage, the Authority thinks it would be inefficient to amend the Benchmark Agreement for the sole purpose of allowing LCE to be incorporated into the calculation of transmission charges. However, the Authority may reconsider this, if the Benchmark Agreement needs to be amended to implement other aspects of a TPM proposal.

6.11 The LCE working paper set out the theoretical foundations for use of LCE to fund the costs of transmission.[79] Since LCE arises from the interaction between buyers and sellers in the wholesale electricity market, using LCE to fund the costs of transmission is a market approach and therefore most preferred under the DME framework.

6.12 There are some issues with the current allocation of LCE, including, in some cases, LCE payments not being received by parties ultimately paying transmission charges, and being allocated to some parties participating in the FTR market. However, these issues are not the principal reasons for the Authority considering use of an LCE credit. Rather, the Authority is required to consider the most efficient means of recovering Transpower's revenue and, in theory, LCE is the most appropriate source of revenue.

6.13 Where LCE has been used to fund FTRs, the LCE credited against the charges of consumers that pay transmission charges would be the residual remaining after funding of FTRs, including remaining FTR auction revenue.

6.14 Submitters were concerned about LCE volatility. However, in general, the volatility in net terms should not differ from the status quo because each customer will still be liable for their full transmission charges but may receive a credit note for LCE.

6.15 Further, FTRs should reduce any volatility since, in theory, the price paid for FTRs will reflect FTR participants' expectations about the average price differences between FTR nodes, rather than the actual price differences (which give rise to the LCE). However, FTRs are unlikely to eliminate volatility because FTRs do not cover the whole grid, and because FTRs are monthly, so the value of FTRs will reflect FTR participants' underlying expectations of the value of FTRs in a particular month.

6.16 The modelling of proposed charges in this paper assumes that LCE is credited as suggested in paragraph 6.4 above. However, in relation to the proposal in paragraph 6.4(b), the Authority is interested in views as to whether it would be preferable to credit remaining LCE against only residual charges, given that residual charges are likely to be the most distortionary.

b) Connection charge

[79] See, in particular, Electricity Authority, Transmission pricing methodology: Use of LCE to offset transmission charges, 21 January 2014, paragraphs 4.6-4.7.

6.17 The current connection charge is a 'deep' connection charge as it includes both assets that provide a physical connection to the grid (which would be the only assets included in a 'shallow' connection definition) plus some assets beyond the point of physical connection that exist to connect parties' electrical assets to the grid.

6.18 The Authority proposes to retain the existing connection charge, which the Authority considers is a market-like charge.

6.19 As noted in section 4, the Authority considers that the treatment of depreciation within the pool of connection assets and the calculation of connection operating expenses may result in inefficiencies. The Authority is still considering whether there would be efficiency gains from moving to DRC-based charging for connection, but is not proposing changes at this stage. The Authority will consult on this as part of the second issues paper if it decides that a change may be desirable. At this stage, the Authority is not proposing to change the calculation of operating expenses.

c) Deeper connection charge

6.20 The Authority proposes to retain the existing connection charge. However, the Authority also proposes to add a deeper connection charge, which would extend the concept of connection deeper into the grid.[80,81,82] To distinguish this potential new charge from the existing connection charge, the potential new charge is referred to as a "deeper connection" charge in this working paper.

6.21 The Authority considers that where assets are predominantly used by a small number of parties, a deeper connection charge would act as a proxy for the likely charges negotiated under a multi-party investment agreement if the parties had to negotiate directly with Transpower for the provision of the assets. The Authority considers that the deeper connection charge is a market-like approach.

6.22 It is proposed that flow tracing be used to identify assets that are predominantly used by a small number of parties. Flow tracing attributes the proportion of the total electricity flow on each transmission asset to individual loads and generators.[83]

6.23 Calculating the Herfindahl-Hirschman Index (HHI)[84] of shared flows can identify assets that are predominantly used by a small number of parties. The Authority considers that the higher the HHI of shared flows by connected parties (either load

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80 As the deeper connection charge is a new proposal, the Authority has produced a companion paper to this options working paper, TPM options working paper: Companion paper describing the detail of the deeper connection charge, June 2015. This companion paper contains more detail on the proposed design of the charge.

81 The Authority is not proposing the deeper connection charge would apply to the HVDC. This is because the HVDC is not an asset required to connect a party to the grid. Rather, it is an asset that is used to connect the North and South Island alternating current (AC) grids.

82 Note that the deeper connection charge is applied to all grid assets, not only those relating to major capex.

83 For further detail on flow tracing see the description in the following paper by the Electricity Commission on the use of flow tracing for transmission pricing, 18 June 2010, available at: https://www.ea.govt.nz/dmsdocument/7123.

84 The HHI is a commonly accepted measure of market concentration, calculated by squaring the percentage market share (in this case load flow) of each market participant and adding these together ie $HHI = \sum_{i=1}^{N} s_i^2$, where s_i is the market (flow) share of firm i in the market (asset), and N is the number of firms. The HHI has a range between 0 (fully competitive market) and 10,000 (monopoly).

or generators or both) the more the asset resembles a connection asset, with the ability for Transpower and connected parties to achieve investment agreements.

6.24 There are two HHIs for every asset – the supply side HHI and the demand side HHI. Assets subject to the deeper connection charge would be defined by the specification of the HHI (discussed below).

<u>Priority of the deeper connection charge compared with other TPM charges</u>

6.25 It is proposed the deeper connection charge would not apply to an asset that is already treated as a connection asset.

6.26 The deeper connection charge would be applied before the AoB charges and residual charges are applied. It is proposed the kvar charge would still apply to provide a price signal to exacerbators of the need for investment in static reactive support equipment. The AoB and residual charges would only apply where the deeper connection charge did not recover Transpower's revenue requirement in relation to an asset.

<u>Design of the deeper connection charge</u>

6.27 The Authority considers that the current connection charges may not recover the full costs of connecting parties to the grid and using the grid.

6.28 There is a spectrum between what can be described as a 'pure' connection asset, whose sole purpose is to connect specific parties (either load or generators or both) to the grid, and a 'pure' interconnection asset, which is common to or shared by all connected parties for transmission of electricity over the grid.

6.29 Within this spectrum, there are assets that are currently defined as interconnection assets, but which are predominantly used by a small number of parties (either load or generators or both).

6.30 If assets deeper in the grid are needed for electricity to be delivered to, or in the case of generators, delivered from, a small number of parties, the Authority proposes that they be treated as (deeper) connection assets, rather than interconnection assets. The Authority proposes that the costs of those assets should be recovered from those connected parties.

6.31 As discussed above, flow tracing would be used to identify assets predominantly used by a small number of interconnection parties only. The HHI of shared flows would be used to identify assets subject to the deeper connection charge.

6.32 The higher the HHI of shared flows by interconnection parties (either load or generators or both) the closer the asset is to a 'pure' connection asset.

6.33 A key judgement, when defining deeper connection assets, is what HHI threshold, or thresholds, to adopt. The lower the threshold, the more assets would be categorised as deeper connection (rather than interconnection).

6.34 The Authority proposes an HHI threshold of 5,000 for each of load and generation.[85] This is the HHI for the equivalent of two firms sharing equally in the flows for an asset. Such a threshold would limit the coverage of the charge to assets used predominantly by only a very few customers.

[85] Applying the same HHI for load and generation is considered appropriate for consistency.

6.35 The flow tracing transmission charging regime that applied in the 1990s suffered from severe price volatility. Although the proposed deeper connection charge also uses flow tracing, it is a fundamentally different type of charge than applied in the 1990s. Paragraph 6.44 discusses the differences.

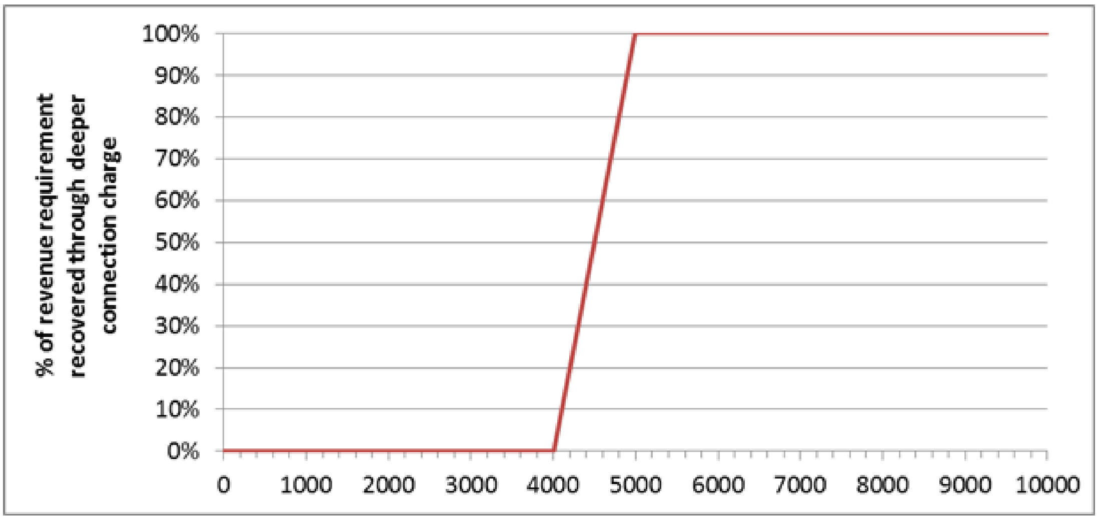
6.36 Because the identification of deeper connection assets involves power flows, the HHI can be subject to change, and this may cause the charge to change between measurement periods. The Authority proposes to address this through the measurement period for determining the HHI, and by applying a 'graduated cut-off' between deeper connection and interconnection.

6.37 The HHI for each transmission asset (excluding current connection assets) would be measured on a backward-looking basis, based on grid usage in the last 5 years. The 5-year period would help address potential charging volatility, that is, from assets fluctuating between interconnection and deeper connection.

6.38 To further mitigate any potential volatility, that is, where assets may fluctuate between HHIs greater and less than 5,000, the Authority proposes to apply a 'graduated cut-off' between HHI=4,000 and HHI=5,000, rather than a 'hard cut-off' at HHI=5,000.

6.39 An asset with HHI=4,000 would be classed as interconnection, with HHI=5,000 or above being classed as deeper connection, and with HHI=4,500 being classed as a 50-50 mix of the two. This is illustrated in Figure 6.

Figure 6: Illustration of graduated cut-off for deeper connection charge, with cut-off between HHI=4,000 and HHI=5,000



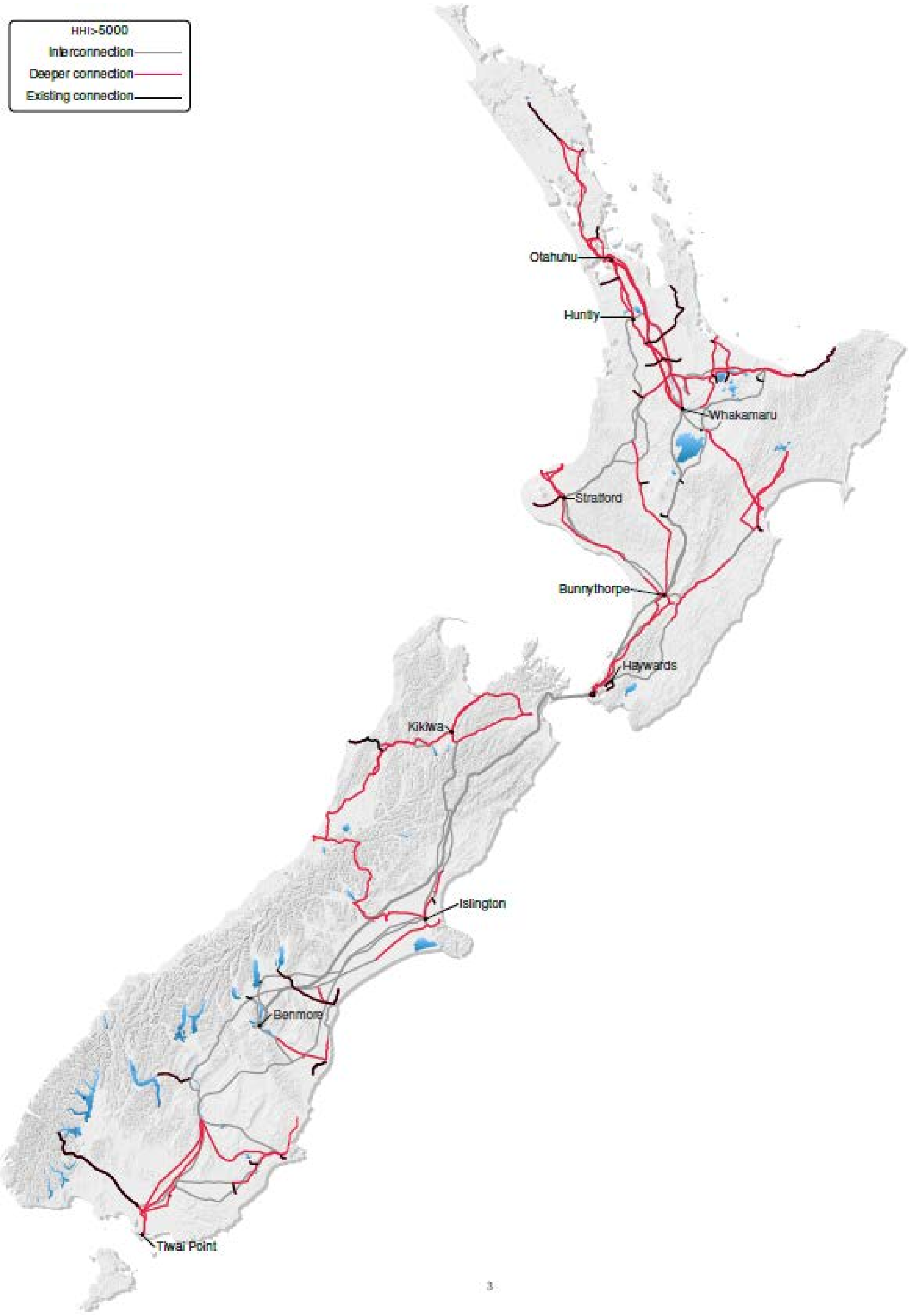
<u>Modelling of the deeper connection charges</u>

6.40 The Authority has undertaken modelling simulations to determine what assets could be classified as deeper connection. Figure 7 shows the transmission lines that are classified as deeper connection assets. Assets at some substations currently classified as interconnection are also classified as deeper connection, but substations are not shown on the map.

6.41 The modelling suggests there would be little volatility from year to year in the classification of interconnection assets as 'deeper connection' or 'true interconnection'. In large part, this is due to the use of a 'graduated cut-off' from HHI = 4,000 to 5,000.[86]

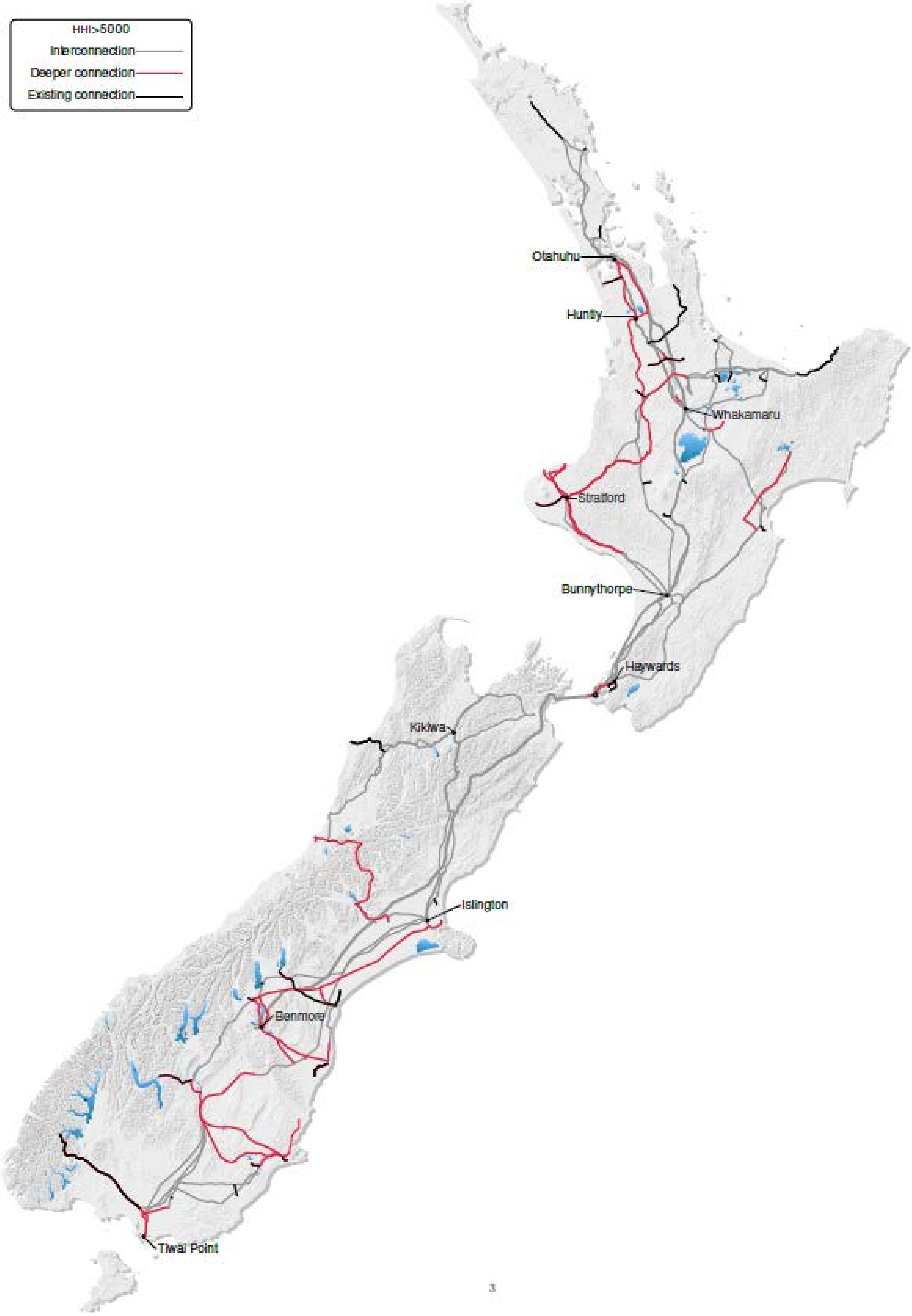
Figure 7: Transmission lines that are classified as deeper connection assets with HHI ≥ 5,000 in the simulated scenario

i. Deeper connection for load (HHI ≥ 5,000)



86 Refer to Electricity Authority, Options Working paper: companion paper describing the detail of the deeper connection charge, June 2015, Appendix C, for details of the Authority's assessment of the stability of the deeper connection charge.

ii. Deeper connection for generation (HHI ≥ 5,000)



6.42 The modelling suggests there is relatively little recovery from generation parties. Less than 20 percent of deeper connection charges would apply to generation parties. In part, this is because many of the assets that primarily exist to serve generation parties are already classified as connection assets.

6.43 Among the deeper connection assets allocated to generation parties would be:

(a) parts of the Wairakei Ring *(with costs paid by Contact, MRP and other owners of geothermal plants in the area)*

(b) some assets that are electrically close to Huntly Power Station *(with costs paid primarily by Genesis)*

(c) some lines between Otago, the Waitaki Valley and Christchurch *(with costs paid primarily by Contact and Meridian).*

6.44 Examples of deeper connection assets allocated to load parties in the simulated scenario, and the main parties that would pay for them, are:

(a) the NIGU lines *(Vector)*

(b) the NAaN lines *(Vector, Northpower, Top Energy)*

(c) circuits between Stoke and Blenheim *(Marlborough Lines)*

(d) the West Coast Upgrade[87] lines *(Westpower)*

(e) circuits between Wairakei and Redclyffe *(Unison, Eastland Networks)*

(f) circuits between Woodville and Masterton *(Powerco, Wellington Electricity).*

Advantages and disadvantages of the deeper connection charge

6.45 Relative to the status quo, the deeper connection charge has the following advantages:

(a) It is market-like, so should promote market-based investment that is closer to the needs of the parties subject to the charge.

(b) If effectively targeted, it should encourage competition in the provision of services provided by deeper connection investments between Transpower and other service providers (including providers of alternatives to transmission services). The charge should not be much affected by demand growth unless this is sufficient for new parties to affect the HHI calculation.

6.46 In addition:

(a) The charge can apply to lines, transformers and substations not covered by the current connection charge (because those assets do not fall within the definition of connection assets).

(b) Calculation of the charge would use just the final pricing solution from SPD[88] and would not use new models (since it just uses SPD), regions, or zoning.

(c) The design of the deeper connection charge means that it would be reasonably stable and would not suffer the problems of the flow tracing

87 http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/west-coast-upgrade-plan/.

88 The final pricing solution from SPD is an input into the flow trace, which in turn is used to calculate the HHIs.

transmission charging regime that applied in the 1990s, where charges changed dramatically because:

(i) of changes in the direction or pattern of transmission flows across the grid

(ii) the flow tracing charge in the 1990s was calculated at only a few points of demand and, the Authority understands, for peak power flows, neither of which are the case for the deeper connection charge.[89]

6.47 Compared with the status quo, the deeper connection charge has the following disadvantages:

(a) Although the Authority considers that an HHI threshold of 5,000 is conservative, establishing an appropriate HHI for the calculation may be controversial given identification of assets as deeper connection is highly dependent on the HHI values used.

(b) The allocation may incentivise parties to alter their behaviour to limit the extent to which they are subject to the charge, which could result in inefficiencies. However, the incentives to do this would be muted where the assets would otherwise be subject to AoB or SPD charges.

(c) The deeper connection charge could discourage consolidation of parties such as EDBs if consolidation meant the HHI rose above the threshold for the deeper connection charge. This could be addressed by applying a lower threshold.

(d) Under Application A[90], this charge would cause large changes to charges relative to the status quo for some transmission customers.

6.48 The Authority's preliminary view is that the advantages of the deeper connection charge outweigh the disadvantages. The Authority would welcome submissions on whether this is the case and whether the charge would be practicable.

d) kvar charge

6.49 The combination of LCE, the connection charge, and the deeper connection charge would not be expected to recover Transpower's MAR, so other charging approaches need to be considered. The next most preferred approach under the DME framework is exacerbators-pay.

6.50 In principle, the deeper connection charge could cover the costs for static reactive support equipment (when the deeper connection charge applies) to address the externality arising from equipment with a poor power factor. However, this may not address the externality. In particular, the deeper connection charge would not provide a direct relationship between the charge to recover the costs of static reactive support equipment and the activity causing the need for the charge: equipment with a poor power factor. Further, the deeper connection charge would not apply to all areas where static reactive support equipment may be required.

6.51 The 2012 issues paper proposed to address the externality with:

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89 Refer to the Electricity Authority, Deeper connection charge companion paper, June 2015, for further analysis of the stability of the deeper connection charge over time.

90 Refer to section 11: Potential application of the new charges.

(a) an exacerbators-pay kvar charge based on the average aggregate kvar draw of off-take transmission customers in areas of the grid where investment in static reactive support is likely to be required

(b) the kvar charge in (a) is to be set at the LRMC of grid-connected static reactive support investments and was to be applied at times of RCPD

(c) a minimum power factor of 0.95 lagging in the Connection Code for all regions. This would require a revision to the Benchmark Agreement.

6.52 Following an analysis of submissions on the 2012 kvar proposal, the Authority considered advancing work on a new kvar charge for static reactive support ahead of its package of proposed transmission pricing policy changes.[91]

6.53 The Authority decided not to advance a kvar charge separately at that time because upward trending power factors suggested that management of reactive power had improved. This improvement reduced the net benefit of bringing forward work on the kvar charge such that the net benefit no longer offset the disruption it would cause to the Authority's work on the overall transmission pricing package. However, the Authority announced its intention to advance the kvar charge along with other elements of the TPM and this intention has not changed. Accordingly, all of the options assessed in the options working paper include a kvar charge with the components (a) through (c) described above.

6.54 Recognising that there may not be an RCPD charge in a revised TPM, the charge is intended to be applied during times of peak demand. The appropriate approach to applying the kvar charge will be considered in the second issues paper.

6.55 The Authority has not modelled the kvar charge given that power factors have improved and therefore income from a kvar charge, at least initially, is expected to be modest. The Authority intends to model the kvar charge in the second issues paper.

e) Beneficiaries-pay charge – area-of-benefit (AoB) charge

6.56 The combination of LCE, the connection and deeper connection charge, and kvar charge would not fully recover Transpower's transmission costs. Accordingly, under the DME framework, beneficiaries-pay is the next charging approach to be considered.

6.57 The Authority proposes that under the Base Option the beneficiaries-pay charge is an AoB charge. An AoB charge was proposed by Castalia, on behalf of Genesis Energy. Castalia's research suggested an AoB charge would better promote efficient outcomes.[92]

6.58 The AoB charge expands the approach for applying beneficiaries-pay proposed under the GIT-based method[93] by applying the method to not only 'reliability' investments but also 'economic' investments. [94,95] The Authority acknowledges

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91 http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/second-issues-paper/.

92 Castalia, Transmission Pricing Methodology: Beneficiary Pays Options, March 2014.

93 The GIT-based charge was proposed to recover the costs of a transmission investment approved on the basis of a reduction in expected unserved energy, or approved on an N-1 basis ('reliability investments').

94 'Economic' transmission investments are investments whose primary benefit lies in allowing the demand for electricity to be supplied in a more cost-effective way.

some submitters' observations that the distinction between reliability and economic investments for the purpose of applying a beneficiaries-pay charge would be arbitrary and lacked sound basis. Under the AoB charge, beneficiaries are the parties generating or consuming at the nodes identified as benefiting from an investment, regardless of the categorisation of the investment.

Thresholds

6.59 The Authority is considering applying the AoB charge to investments (or in respect of assets within those investments) not covered by the deeper connection charge as follows:

(a) investments that were both approved and commissioned in the period from 28 May 2004 until publication of any guidelines to introduce an AoB charge, with a cost above $50m

(b) investments either approved or commissioned (or both) following publication of any guidelines ('new' investments) with a cost above $20m.

6.60 The AoB charge could also be applied to HVDC Pole 2, as discussed in paragraphs 6.64 to 6.66.

6.61 The rationale for including investments since 28 May 2004 above $50m is that this includes all large investments approved under a regulatory process. A cut-off date (28 May 2004) has been applied to the AoB charge to provide a 'line in the sand' for determining what assets are subject to the AoB charge. Approval under a regulatory process is relevant for the AoB charge as information provided in the regulatory approval process is used to identify beneficiaries and, therefore, apply the charge.

6.62 Further, consistency of treatment where assets are of similar timing is an important consideration. If beneficiaries of new investments are subject to the AoB charge, it is appropriate that beneficiaries of large recent investments are also subject to the AoB charge. This can also be justified on competitive neutrality grounds: if parties benefiting from large investments in the future are subject to the AoB charge, competitive neutrality implies that parties benefiting from large recent investments should also be subject to the AoB charge. This will ensure that competition is not harmed because beneficiaries of large investments beyond the deeper connection boundary all face the costs of the investment.

6.63 The Authority proposes the date of publication of TPM guidelines to introduce an AoB charge as the basis for defining 'new' investments. This date would allow parties to incorporate new charges on new investments into their own investment decisions. It is proposed that this would apply to investments that are approved or commissioned (or both) after this date, as parties are potentially able to influence both the commissioning and approval date for investments and therefore investment efficiency.

6.64 The rationale for the threshold for new investments (that is, with a cost above $20m) is that it is the same as the threshold used by the Commerce Commission for major capex under its Capital Expenditure Input Methodology (Capex IM).

[95] Although, in the modelled scenarios, the costs of reliability investments are not recovered through the area-of-benefit-based charge – because all the reliability investments considered appear to be deeper connection ie they are entirely made up of deeper connection assets.

Application of AoB charge to Pole 2?

6.65 Consistency of treatment could imply that HVDC Pole 2 should be charged on the same basis as Pole 3.[96] Pole 2 and 3 provide the same service – delivery of electricity between the North and South Islands – and, in principle, should be treated the same in the way they are priced.

6.66 However, Pole 2 was not approved under a regulatory process as it was commissioned in 1992. Pole 2 is a more historical investment relative to investments above $50m approved since 28 May 2004. Investments covered by the proposed 28 May 2004/$50m threshold have either only been recently commissioned (for example, Wairakei Ring and Pole 3) or are yet to be built (for example, parts of LSI Renewables). This means the bulk or all of the costs of these investments are yet to be recovered. This is not the case with Pole 2.

6.67 Further, changing pricing on historical investments can be justified if there are significant dynamic efficiency benefits, but this does not appear to be the case in relation to Pole 2. The Authority would therefore appreciate submissions on whether Pole 2 should be included in a beneficiaries-pay charge, such as the AoB charge. As discussed below, the Authority has modelled the AoB charge as including Pole 2.

Consideration of a static or dynamic area-of benefit charge

6.68 A key design question is whether an AoB charge would be:

(a) static, with the charges being allocated to the beneficiaries identified in the original investment approval document, or

(b) dynamic, with the potential for a different set of parties to be charged if the situation changed over time.

6.69 The static approach would have the advantages that, once the investment was approved:

(a) the allocation of charges to parties could largely be predicted in advance, providing participants with a basis on which to make long-term decisions

(b) there would be no incentive for parties to change their use of the grid in an attempt to change the set of parties identified as beneficiaries of the investment

(c) there would be no incentive for parties to spend resources on lobbying for a different set of beneficiaries to be charged.

6.70 On the other hand, the static approach would have the disadvantages that:

(a) after some time had passed, charges might no longer be aligned with benefits

(b) the mismatch between charges and benefits might reduce the durability of the TPM.

6.71 If the dynamic approach was taken, then the identification of beneficiaries might be carried out periodically (for example, every 5 years), or when the changes in benefits exceeded a pre-determined threshold.

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96 The Authority estimates that Pole 2 has a required return of approximately $55M per annum.

6.72 For instance, a periodic review process could be carried out in which the following steps would be taken for each eligible investment:

(a) assess the private benefits, perhaps using a similar methodology to that employed by the Authority to assess the private benefits of the HVDC link[97]

(b) calculate the percentage of the total private benefits for each group of participants

(c) compare these percentages with the percentage breakdown currently used in the AoB charge for that investment

(d) determine whether the sum of squared differences in percentages exceeded some threshold

(e) if so, update the allocation of charges for the investment.

6.73 The Authority's preliminary view is that AoB charges should only be altered when changes in benefits exceeded a pre-determined threshold.

6.74 Examples of situations where the AoB charge might be recalculated include an event causing a major change in flows, such as a major permanent reconfiguration of the grid, a major new investment or the entry or exit of a major customer.

6.75 This would mean that alterations to the allocation of the AoB charges would be the exception rather than rule. Taking such an approach would help promote certainty, which would in turn help promote efficient investment. On the other hand, providing the opportunity to alter the charge would increase the likelihood of lobbying for change, and there would be uncertainty while allocation of the charge was being reviewed. However, since the threshold for change would be high, these problems should be minimal.

6.76 Note that the SPD approach in the Base Option + SPD takes a more dynamic approach to the calculation of benefits than the AoB charge, with beneficiaries being identified through half-hourly market solves.

<u>Allocation of the area-of-benefit charge</u>

6.77 It is proposed the AoB charge would be applied to load on a capacity basis. This is because a capacity-based allocation minimises distortion as it would be fixed regardless of offtake and can only be altered if a customer changes their capacity, such as their connection transformer.[98]

6.78 It is proposed that allocation of the AoB charge to generation would be on a MWh basis. Allocation to generation on a MWh basis avoids the problem that allocating charges on a capacity basis would disincentivise peaking generation.

6.79 For this working paper, the Authority has modelled the AoB charge as follows:

(a) charges on load are allocated in proportion to:

(i) deemed capacity, for EDBs – calculated as the sum of the nominal capacities of the active ICPs in their network area. The nominal

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97 Refer to Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012, Appendix C.

98 Refer to the Electricity Authority, Deeper connection charge companion paper, June 2015, for a discussion on allocation options, including a capacity option (transformer capacity) or possible proxies for capacity (AMI/AMD, per MWh, per ICP or a combination of several of these allocation methods).

capacity depends on the ICP's metering category code, ranging from 20 kW for category code 1 to 2500 kW for category code 5[99]

(ii) Anytime Maximum Demand (AMD), for major industrial customers

(b) charges on generation are allocated in proportion to MWh injection.

6.80 The rationale for allocating charges to major industrial consumers on the basis of AMD is that AMD is a proxy for capacity for these customers. A proxy is required for major industrial consumers because in some cases their installed capacity substantially exceeds their actual use. Alternatively, these customers could be charged on an actual capacity basis but the prudent discount policy applied where a customer was considering reconfiguring their assets to limit their charge.The Authority is interested in submitter views on the most appropriate allocation mechanism for the AoB charge. The Authority is also seeking submitter views on whether the AoB charge for an investment should move to a congestion or peak-based charge once congestion is triggered for that investment, as is being considered for the deeper connection charge (see section 4 of the companion paper).

6.81 In practice, the AoB charge could result in charges exceeding the incremental private benefits of some participants, which could distort their behaviour, including to the extent that they potentially disconnect. This would need to be dealt with through the prudent discount policy.

6.82 Recovering the costs of an investment through an AoB charge provides an implicit price signal before the investment because investors should, in principle, be forward-looking. That is, the parties that would pay the AoB charge for a particular investment are likely to anticipate before the investment that they will have to pay the charge. Those parties will take this charge into account in their own decisions, including decisions on whether, and the extent to which, the parties engage in the Commerce Commission's investment approval decisions.

Modelling of the area-of-benefit charge

6.83 Modelling for the AoB charge is described in Appendix A. Under the scenario modelled, the AoB charge recovers approximately $145 million annually under the Base Option.

6.84 In practice, Transpower would determine which groups of parties were the beneficiaries of each investment (both for existing and new investments), and how the benefit of the investment would be determined between these groups of parties. However, for this options working paper, the Authority has determined the beneficiaries and the breakdown of benefit, based on:

(a) the analysis of net private benefit for the HVDC[100]

(b) Transpower's investment approval documents, for the other investments considered.

6.85 Table 6 lists the investments that are included in the calculation of AoB charges in the simulated scenario.

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99 Refer to Appendix A.

100 Refer to Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012, Appendix A.

6.86 The extent to which costs of these investments are recovered under the options varies. Under the Base Option and Base + LRMC, the AoB charge mainly recovers the costs of economic investments because the costs of major reliability investments (such as the NAaN and NIGU) are largely or wholly recovered through the deeper connection charge. The costs of some major economic investments (such as LSI Renewables) are also largely recovered through the deeper connection charge.

6.87 Under the Base Option + SPD, the AoB charge also mainly recovers the costs of economic investments but the amounts to be recovered are smaller than shown in Table 6 because part of the costs of these investments are recovered through the SPD charge.

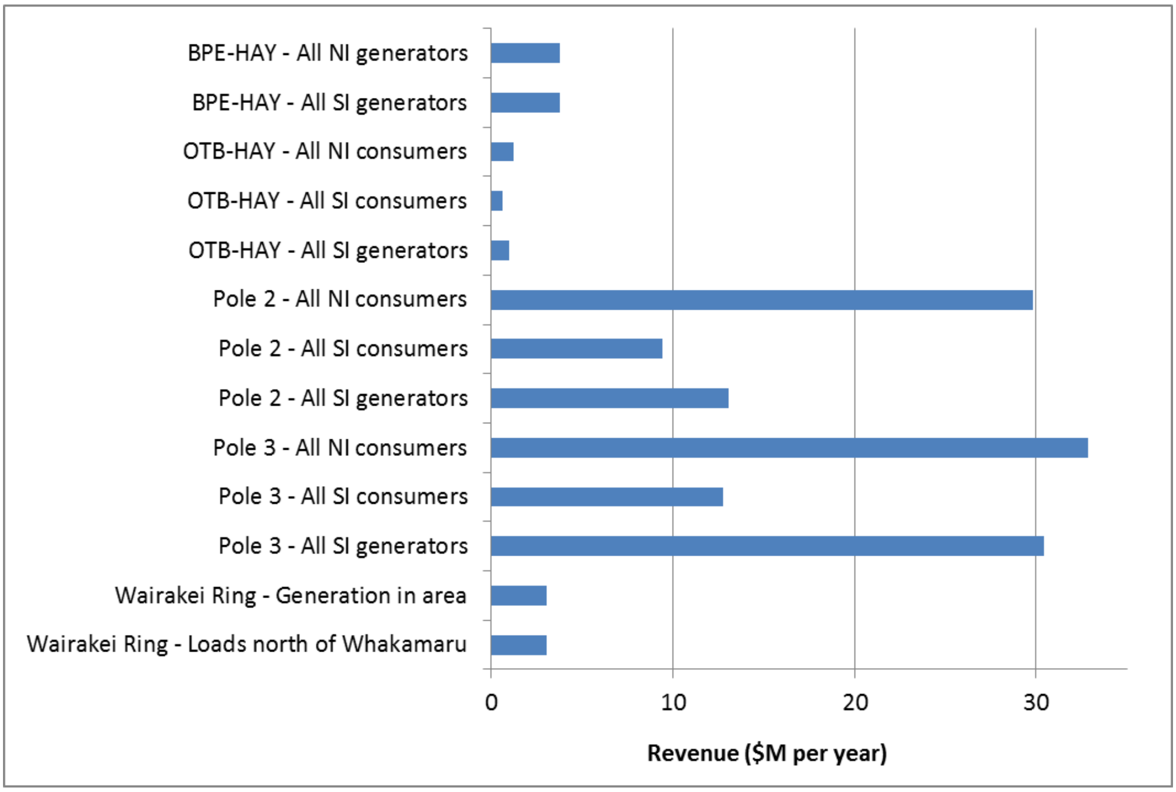
6.88 Also because identifying beneficiaries can require judgement, if Transpower applied the AoB method, it might determine a different breakdown of benefits from that shown in Table 6.

Table 6: Investments for which the AoB method is applied in the simulated scenario

Investment	Amount to be recovered ($M per year)	Parties from which the costs are recovered	Reference
Economic investments			
HVDC Pole 3	80	SI generators – 40% SI loads – 28% NI loads – 72%	http://www.ea.govt.nz/dmsdocument/13799
HVDC Pole 2	55	SI generators – 25% SI loads – 18% NI loads – 57%	
Wairakei Ring	6.5 *(given that part of the cost is recovered through the deeper connection charge)*	Loads north of Whakamaru or in Hawkes Bay – 50% Central NI geothermal generation, Waikato hydro at or above Atiamuri, Bay of Plenty generation – 50%	https://www.ea.govt.nz/dmsdocument/1904
Bunnythorpe-Haywards (BPE-HAY) reconductoring	8	SI generators – 40% NI generators – 60%	http://www.comcom.govt.nz/dmsdocument/925
Oteranga Bay-Haywards (OTB-HAY) reconductoring	3	SI generators and loads in both islands – same breakdown as for HVDC Poles 2 and 3 combined	Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

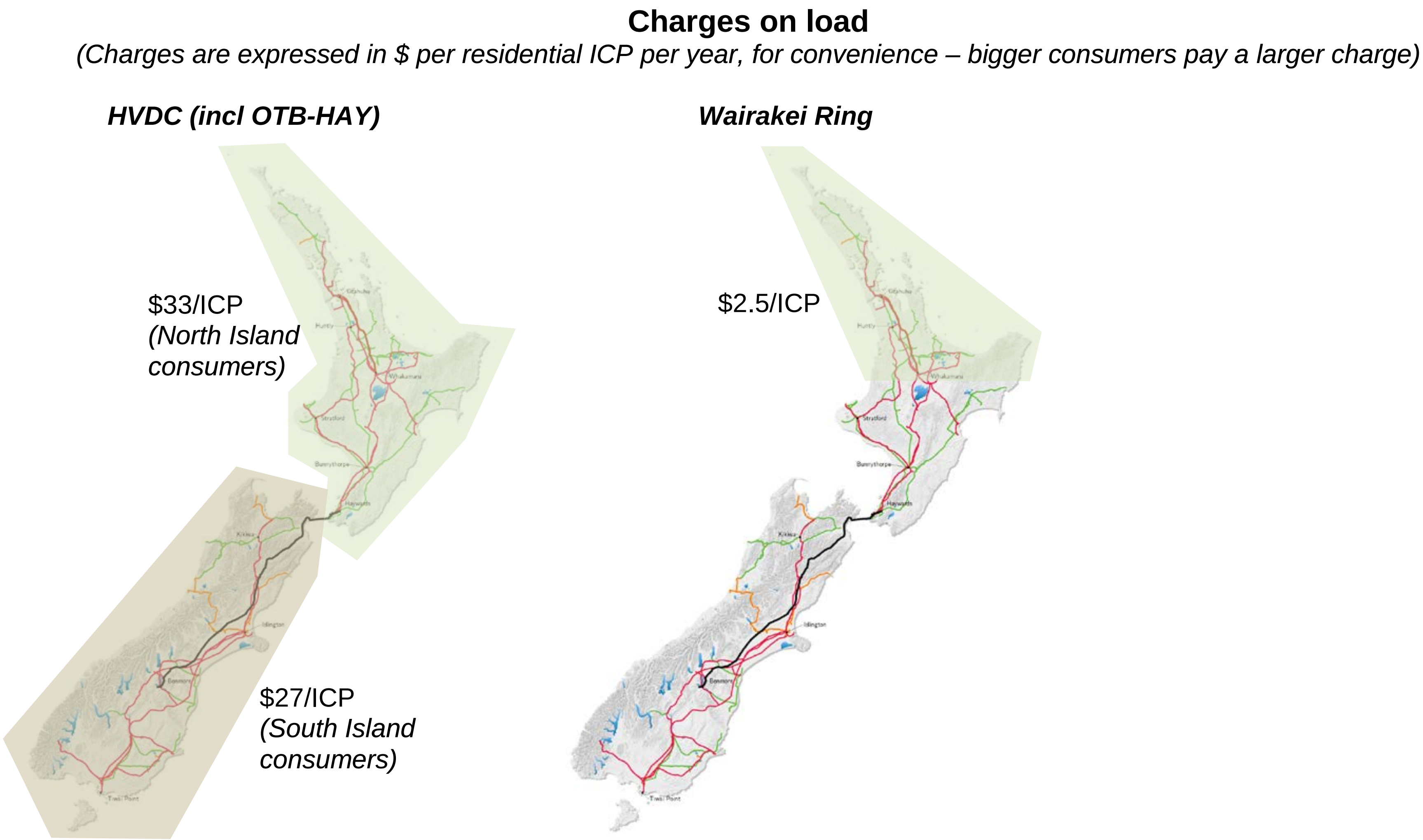
Figure 8 below shows the breakdown of AoB charges between groups of parties. This covers the investments set out in Table 6.

Figure 8: Total area-of-benefit charges, by investment, in the simulated scenario



6.89 Figure 9 below shows the charging rate for each group of parties, for each investment.

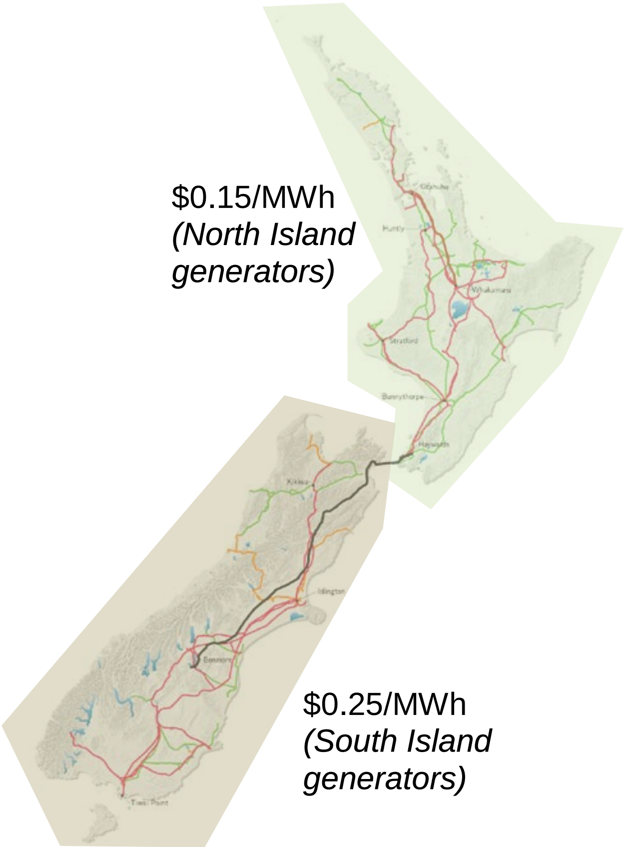
Figure 9: Maps of area-of-benefit charges in the simulated scenario



Charges on generation

BPE-HAY

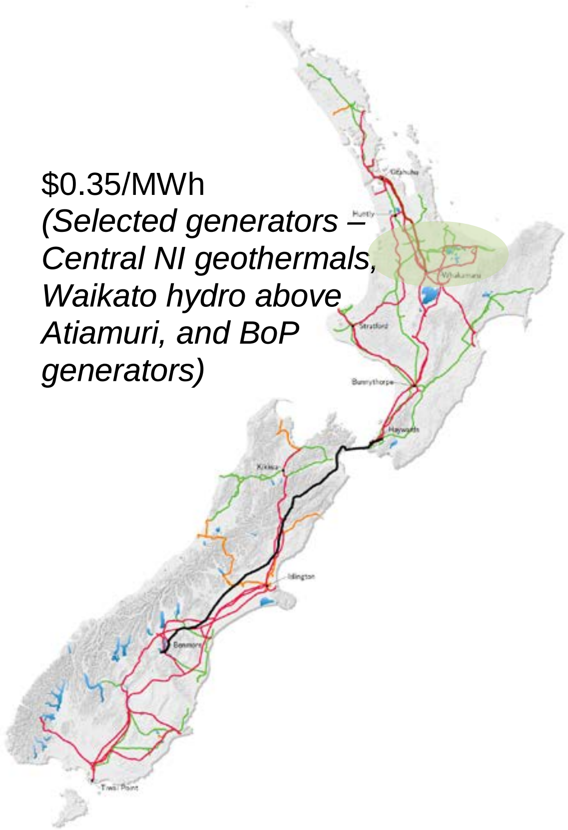
$0.15/MWh
(North Island generators)



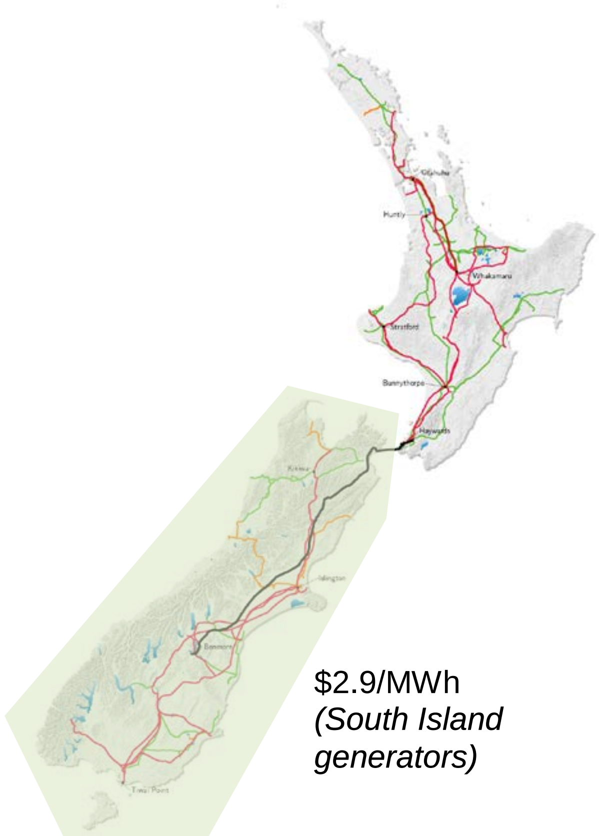
$0.25/MWh
(South Island generators)

Wairakei Ring

$0.35/MWh
(Selected generators – Central NI geothermals, Waikato hydro above Atiamuri, and BoP generators)



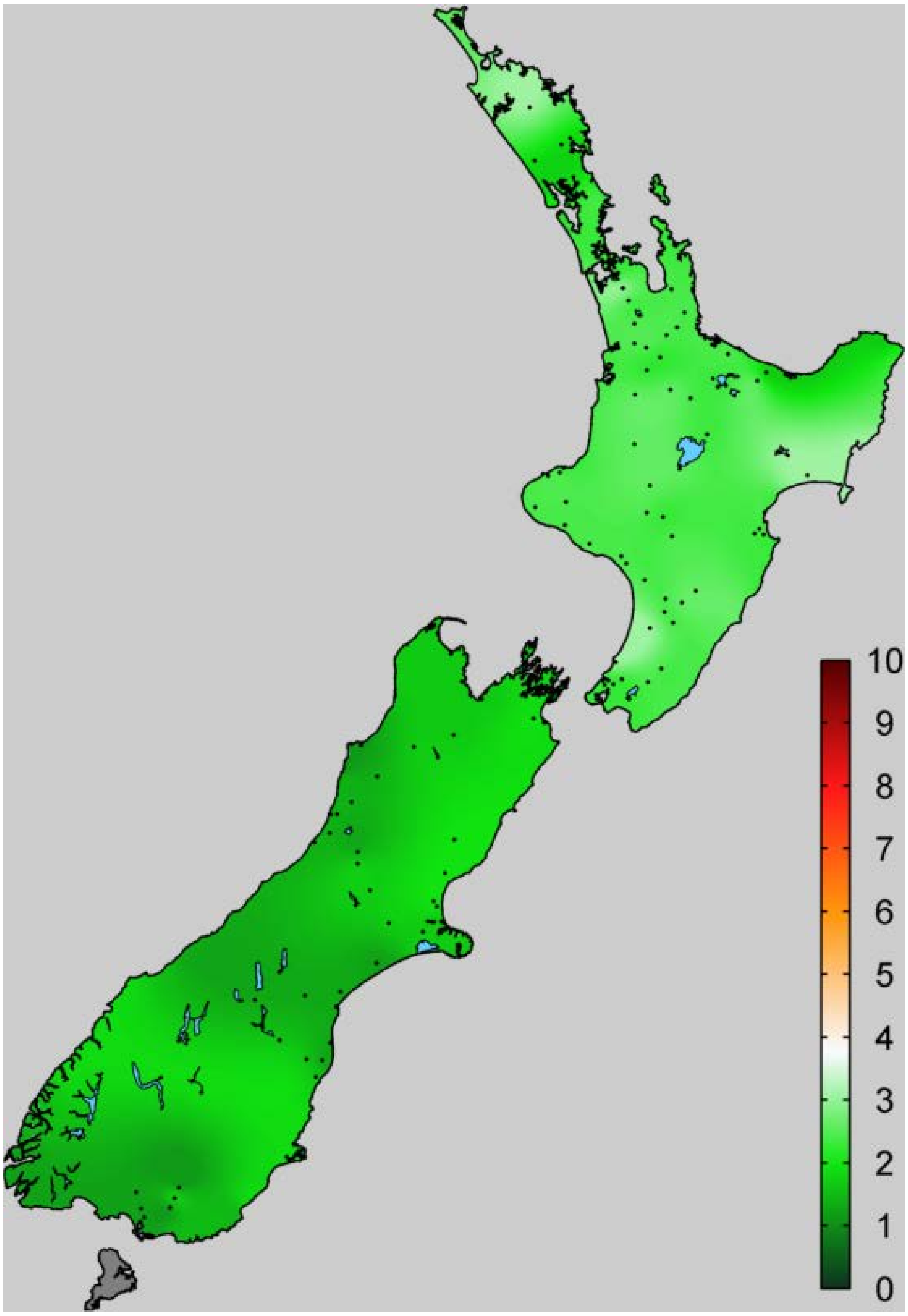
HVDC (incl OTB-HAY)



$2.9/MWh
(South Island generators)

6.90 Figure 10 shows simulated AoB charges on load, in a 'heat map' format.

Figure 10: Area-of-benefit charges on load, in fully variabilised terms ($/MWh)[101]



6.91 The AoB charge on load shows little locational variation. This is because it is mainly made up of a charge that is levied on all load in both islands in respect of the HVDC link.

101 This is net of LCE.

f) Residual charge

Selection of an appropriate residual charge

6.92 The combination of the LCE credit, connection charge and deeper connection charge, kvar charge and AoB charge would not fully recover the full costs of Transpower's services, that is, Transpower's MAR. Accordingly, a residual charge would be required to recover remaining costs. The deeper connection charge and the AoB charge should provide the signals necessary to promote efficient investment, and nodal pricing provides additional signals to promote efficient operation.

6.93 The Authority's preliminary view is that the residual charge should be designed to limit distortion in the use of the grid resulting from the imposition of the charges. This is on the assumption that a pricing signal is not necessary to promote efficient investment in capex less than $20m) not covered by the connection or deeper connection charges.

6.94 The Authority expects that much of the base capex (which is around $250m per year) would be covered by these charges and that the benefit of providing an additional signal in relation to base capex through the residual charge would be low. The Authority would welcome submitters' views on whether a price signal through the residual charge is needed to promote efficient investment in relation to base capex.

Proposed residual charge – postage stamp (flat rate) capacity-based charge on load

6.95 The Authority proposes that the residual charge be calculated according to the connection capacity of loads.

6.96 The Authority considers that a residual charge calculated according to connection capacity may limit distortions in use of the grid because it would be relatively difficult to alter.

6.97 Further, in general, a party's maximum potential demand for transmission services is determined by the capacity of its connection to the grid, whether directly or indirectly. Charging on a capacity basis would spread the cost across all load parties that use the grid rather than concentrating it just on those using the grid during peaks, as under the current RCPD charges. This should broaden the base upon which the charge is levied, which would lower its rate, and reduce distortions from the charge.

6.98 A residual connection capacity charge could be applied to both load and generation. The Authority considers that it would be most efficient, and minimise distortions, to charge load only.

6.99 The Authority acknowledges this is a departure from its thinking in the 2012 issues paper where the Authority proposed a 50:50 split between load and generation for the residual charge.

6.100 The rationale for the Authority's revised proposal is:

(a) a capacity charge would not be competitively neutral amongst different generation types and would disadvantage generation types with low capacity utilisation, for example, wind and back-up or peaker generation

(b) to the extent generators would be able to pass-through the charge – influenced by the fact all generators would be subject to the charge and would need to recover the costs – the residual charge would be converted into a variable charge which would be allocatively inefficient.

6.101 While at first blush the change may appear to disadvantage load, the Authority would stress the distinction between direct and indirect incidence of charges. Under the Authority's revised proposals, the charges on load would be passed through to end-users via distribution charges (with transmission charges being pass-through costs provided for under the Part 4 Commerce Act determinations that apply to EDBs) and, in turn, via final retail tariffs. [102] Under a 50:50 split between load and generation, a significant portion of the charges to generation would likely be passed through via higher wholesale electricity prices and, in turn, via higher variable charges in final retail tariffs.[103,]

Allocation of the charge

6.102 The Authority has not yet developed a pure capacity-based charge on load. Therefore, for the purpose of this working paper, the Authority has modelled the capacity-based charge as being allocated in proportion to:

(a) deemed capacity, for EDBs – calculated as the sum of the nominal capacities of the active ICPs in their network area. The nominal capacity depends on the ICP's metering category code, ranging from 20 kW for category code 1 to 2500 kW for category code 5.[104]

(b) AMD, for major industrial customers. The reason for this is that the capacity of some direct connect customers' connections substantially exceeds their demand for transmission services, so a reasonable proxy for their connection capacity requirements is AMD. If allocating the residual charge to industrial consumers on an AMD basis resulted in activity to embed their demand (that is, obtain electricity supply through the local distribution network), this would need to be addressed through the prudent discount policy.

6.103 The outcome of modelling is illustrated in Figure 4, with the capacity charge (residual charge) on load recovering about $350 million per year.

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102 Appendix G discusses the advantages and disadvantages of charging EDBs versus retailers in relation to charges on mass-market load.

103 End-users would only be advantaged by imposing residual charges on generation to the extent generators were unable to pass-through the charges.

104 Refer to Appendix A.

7 Base Option + LRMC

Description of option

7.1 As Table 4 shows, the Base Option + LRMC consists of seven components:

(a) LCE credit

(b) the existing connection charge

(c) a deeper connection charge

(d) a kvar charge

(e) an LRMC charge

(f) an AoB beneficiaries-pay charge on post-2004 investments not covered by (b) – (d) above, and

(g) a residual charge – postage stamp (flat rate) capacity-based charge on load.

7.2 This section addresses the LRMC component. The other components are addressed in section 6.

LRMC charge

Description and methodology of the LRMC charge

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

7.4 The ENA is of the view that "An LRMC charge would provide transmission users with price signals that approximate the long run costs of their transmission usage at peak times. This is desirable from a dynamic efficiency perspective to inform transmission users' (including consumers') decisions on their usage of the transmission system and their investment in alternatives (including, for example, in distributed generation)".[105]

7.5 As was discussed in the LRMC charge working paper, LRMC charges are market-like.[106] In particular, as in workably competitive markets such as hotels and airlines, prices would reflect LRMC during periods of congestion.

<u>Marginal incremental cost (MIC) is the Authority's preferred LRMC approach</u>

7.6 The LRMC charge working paper noted there are three main approaches to calculating LRMC:[107]

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105 ENA, Submission on Transmission Pricing Methodology: Beneficiaries-pay options, 25 March 2014, paragraph 46.

106 Electricity Authority, Transmission Pricing Methodology Review: LRMC charges, working paper, 29 July 2014, available at: http://www.ea.govt.nz/dmsdocument/18259.

107 Electricity Authority, Transmission Pricing Methodology Review: LRMC charges, working paper, 29 July 2014.

(a) MIC, which considers how future costs will change as a result of a permanent change in demand

(b) Long-run incremental cost (LRIC), which calculates the annualised cost of the next proposed investment and divides this by the permanent increment in demand

(c) Average incremental cost (AIC), which calculates the additional capital and operating expenses over the planning period required to meet a permanent increase in demand (over and above forecast increases in demand) for the planning period. AIC is then derived by dividing the increased capital and operating expenditure by the total increase in demand.

7.7 The Authority proposes that, if an LRMC charge were introduced, the methodology for calculating LRMC should be MIC. The Authority considers that MIC is likely to be most consistent with providing efficient price signals. As noted in the LRMC working paper, the MIC approach produces volatile prices, but this reflects the transmission cost implications from changes in demand for transmission services and so would provide an efficient pricing signal. As noted by Nova Energy in its submission on the LRMC working paper, the MIC approach mirrors the LCE rising as demand increases to match supply.[108]

7.8 The Authority is not convinced the AIC method would provide a sufficiently efficient price signal because it is based on an average cost of a series of investments to meet forecast demand. This means the AIC method is more likely to over- or under-signal the cost implications of changes in demand than MIC or LRIC. Further, the AIC method is more vulnerable to error than MIC or LRIC because it takes into account all future investment required to meet future demand but future transmission investment requirements become increasingly uncertain the longer the future time horizon.

7.9 The LRMC working paper noted that the LRIC method is intermediate between MIC and AIC, and has the advantage of being less volatile than the MIC method. However, the Authority considers that MIC better matches the signals provided through nodal pricing.

<u>Use of Transpower's existing forecasts</u>

7.10 The Authority proposes that an LRMC charge would be applied to all forecast transmission investment above $20 million for a project or programme that would not be subject to the connection or deeper connection charges. It is proposed that the forecast investment used to calculate the LRMC charges would be derived from Transpower's 10-year expenditure and demand forecasts, which are published as part of the Commerce Act Part 4 regulatory regime.[109] As PwC noted in its submission on the LRMC working paper, use of these forecasts would avoid "unnecessary work and cost in creating new forecasts for the purpose of determining LRMC prices. It also defines a suitable time period over which LRMC can be reasonably assessed. While 10 years is a short period for

108 Nova Energy, Re: TPM Review – LRMC charges, 23 September 2014.

109 Refer, for example, to: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Annual_Planning_Report_2014.pdf.

assessing future capacity upgrades, to go beyond Transpower's own forecasts is likely to increase concerns regarding subjectivity and forecast error."[110]

Thresholds

7.11 A threshold of $20 million means that a price signal from the LRMC charge would only be provided in relation to major capex under the Commerce Commission's Capex IM.[111] This would mean that base capex projects or programmes (that is, capital investment projects or programmes with a cost of less than $20 million[112]) would be excluded from the LRMC charge. While base capex is sizeable (forecast to be $253.6m in 2014/15[113]), the Authority expects much of the base capex projects or programmes would relate to assets either subject to the connection charge or proposed to be subject to the deeper connection charge.

Application

7.12 The Authority proposes that the LRMC charge would be applied at peak congestion rather than at peak demand as it is transmission congestion rather than peak demand that is the underlying driver of transmission investment. As noted in the LRMC working paper, one method of doing this is according to a saturation ratio, or the ratio of flow on a line to its capacity.[114] In modelling the LRMC charge, the Authority applied the charge in geographical areas forecast to have transmission investment in the period 2017-2027 according to demand for transmission services in the trading period with the highest saturation ratio.

7.13 As the LRMC working paper noted, because nodal pricing provides an efficient signal about SRMC, it is appropriate to adjust LRMC charges for this signal. Adjustment would ensure that LRMC charges do not provide an excessive pricing signal, that is, double counting of SRMC and LRMC pricing signals. This can be done by subtracting the average nodal price differences from the calculation of LRMC.

7.14 The LRMC charges would not be adjusted for revenue recovered from LCE. This is because the LRMC charge is intended to provide a price signal that reflects the costs of the future investment required to meet changes in demand. As a result, if the LRMC charge were adjusted for LCE, it would understate the LRMC.

7.15 It is proposed that LRMC charges would be calculated on the basis of the net capacity required by a participant in the trading period in which LRMC charges are calculated. This is because it is net capacity that drives transmission investment requirements. The net capacity calculation would vary depending on whether the investment is driven by an import constraint, in which case the charge would be calculated according to net load (that is, load minus generation),

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110 PricewaterhouseCoopers, Submission to the Electricity Authority on Transmission Pricing Methodology: LRMC charges, 23 September 2014.

111 Commerce Commission, Transpower Capital Expenditure Input Methodology Determination, 31 January 2012.

112 Commerce Commission, Transpower Capital Expenditure Input Methodology Determination, 31 January 2012, base capex programme threshold and base capex project threshold.

113 Transpower, Annual Regulatory Report 2013/14, section 5.5, page 31.

114 Electricity Authority, Transmission Pricing Methodology Review: LRMC charges, working paper, 29 July 2014, paragraph 8.18.

or an export constraint, in which case the charge would be calculated according to net generation (that is, generation minus load).

7.16 It is proposed that the LRMC charge would apply to generators, EDBs (for mass market load) and direct connect consumers. Applying the LRMC charge to distributors would be consistent with the approach under the current interconnection charge where transmission charges for mass market load are applied to EDBs.

7.17 In summary, it is proposed that if an LRMC charge were introduced, it would be:

(a) calculated using MIC

(b) applied according to peak congestion trading periods

(c) adjusted to reflect the price signal provided by nodal prices

(d) calculated according to the net capacity required by a participant during congested periods.

Example of how the LRMC methodology could be applied

7.18 Consider an example in which an upgrade U may be required to provide import capacity into region R. The upgrade U meets the criteria for the LRMC charge, that is, it is expected to be an interconnection investment in excess of $20M. The LRMC charge in relation to upgrade U would be calculated as follows:

- Define F as = (demand in region R) – (generation in region R). Ignoring losses, F = net transmission flow into region R.
- Define C, the saturation ratio, as = F / (transmission capacity into region R).
- LRMC = $\dfrac{\text{PV of a year's deferral of the investment U}}{\text{Expected average increment in F}}$
- The parties affected by the charge are loads and generators in region R.
- Consider charges in the year 2018. These charges are based on load and generation at peak congestion, that is, the trading period of 2018 in which C is highest.
- In the year 2018, each load party's charge is LRMC multiplied by L, where L equals their load during peak congestion in region R in 2018 minus their load during peak congestion in region R in 2017). This means that if a party's charge is negative they would receive a credit rather than pay a charge.
- In the year 2018, each generation party receives an LRMC charge multiplied by G, where G equals their generation during peak congestion in region R in 2018 minus their generation during peak congestion in region R in 2017. This also means that if a party's charge is negative they would receive a credit rather than pay a charge.

Modelling of the LRMC charge

7.19 The Authority has modelled an LRMC charge based on the LRMC-MIC design described above. Appendix A provides details on the calculation and the assumptions used.

7.20 In practice, the LRMC charge would be calculated based on information about possible investments from Transpower's planning documents (such as the

Annual Planning Report). For this working paper, the Authority has instead prepared a list of possible future investments. This list is provided in Table 7, which also shows the LRMCs for investments. The Authority emphasises that this list is not intended to accurately predict the course of future transmission investment. Rather, it presents a somewhat plausible view of how the investment landscape might look in 2017, for the purpose of illustrating the LRMC method.

7.21 LRMC is calculated over a 10-year horizon, from 2017 to 2027. An 8 percent real discount rate is used.

7.22 Note that Table 7 excludes investments that would be highly likely to be defined as deeper connection as illustrated in Figure 7 – such as incremental upgrades supplying the UNI or the North Auckland and Northland (NAaN) region. Even some of the investments that *are* included in Table 7 could potentially be deemed to be deeper connection; it is not yet clear.

Table 7: LRMC calculations in the simulated scenario

Project	Explanation	Driven by	Estimated cost ($M real in 2014 dollars)	Anticipated commissioning year	Net quantity during annual peak congestion (MW)		Estimated LRMC ($/kW)
					2016 actual	At point where investment is needed	
Lower North Island transmission reinforcement [115]	Various possible upgrades between Bunnythorpe and Whakamaru, with the two main purposes of: - supporting winter peak load growth north of Whakamaru - reducing export constraints from the area south of Bunnythorpe	Peak demand in (or peak congestion into) the region north of Whakamaru	75 (half of this cost is allocated to each of the two identified groups)	2024	500	1300	15
		New generation south of Bunnythorpe			1100	1400	41
Upper South Island grid upgrade - stage 2 [116]	Investment to manage peak demand in the USI. May include new switching stations (eg Orari) between the Waitaki Valley and Christchurch	Peak demand in (or peak congestion into) the USI region	58	2020	830	950	92
Upper South Island voltage stability[117]	Mixture of static and dynamic reactive support, driven by USI load growth	Peak demand in (or peak congestion into) the USI region	50	2027	830	1180	53

115 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

116 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

117 Refer Section 6.8.1 of Annual Planning Report 2014 at: https://www.transpower.co.nz/resources/annual-planning-report-2014.

7.23 As an example of the calculation, LRMC for stage 2 of the USI grid upgrade is calculated as $92/kW – derived as:

$$\frac{\$58M \times ((1 + 0.08)^{-(2020 - 2017 - 1)} - (1 + 0.08)^{-(2020 - 2017)})}{(950\ MW - 830\ MW) * 1000 / (2020 - 2017)}$$

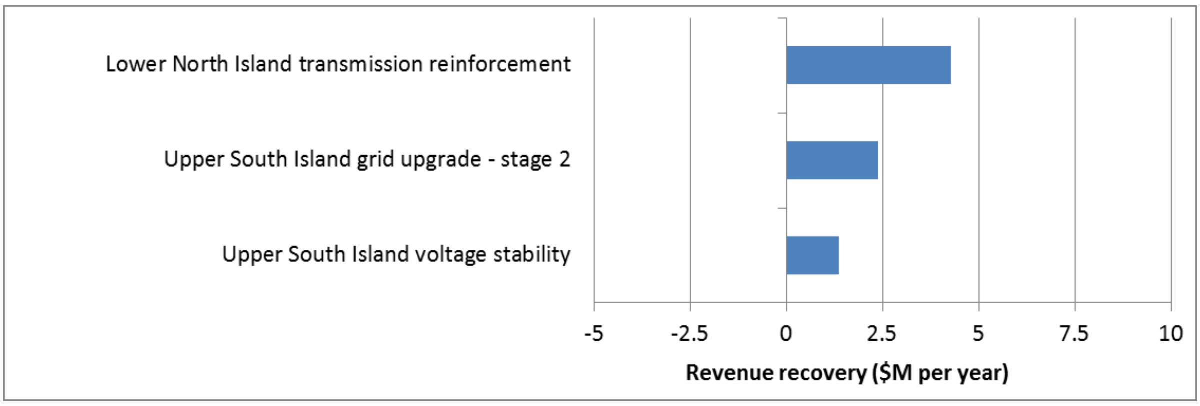
(The factor of 1000 converts MW to kW.)

Results of LRMC modelling

7.24 Figure 4 shows the distribution of LRMC charges across groups of parties. In the scenario, LRMC charges are mainly paid by USI loads. However, the distribution of charges could be very different if there were changes in electricity consumption or generation. For instance, if USI loads (or their representatives) acted to reduce USI coincident peak demand, then their LRMC charge would reduce accordingly in the year concerned and could even become negative, which would mean they receive a payment from Transpower. Negative charges would be appropriate as they provide an efficient incentive (since they are based on LRMC) for parties taking action to defer transmission investment.

7.25 Figure 11 shows the amount of money that is recovered through the LRMC charge, for each future investment. The total amount of money recovered is quite small (comparative to other charges) – an average of just $8M per year over the 3-year period for which charges are calculated. One reason for this is that the increase in peak demand over the simulated period is quite modest. Another is that deeper connection investments are excluded. Nevertheless, the LRMC charge provides an efficient signal for deferral of future interconnection investment.

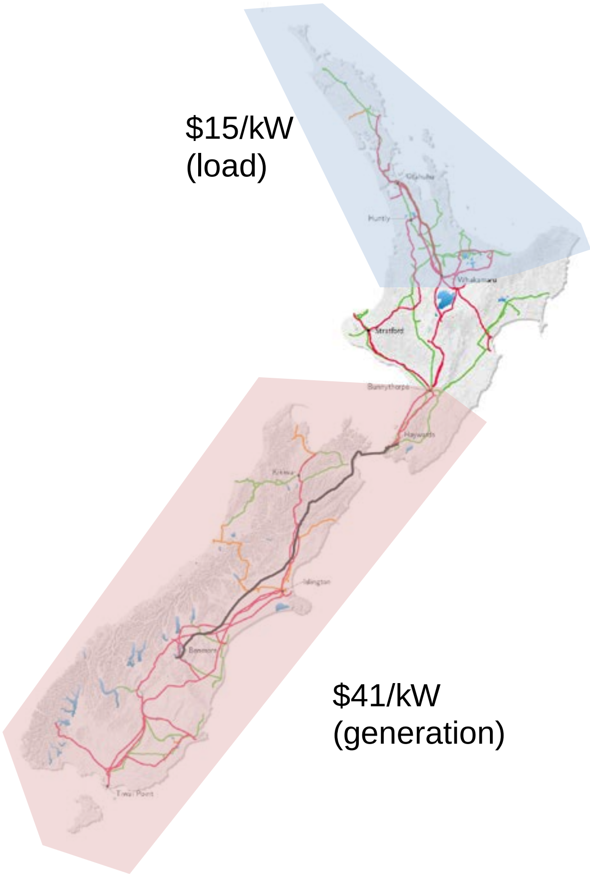
Figure 11 Total LRMC charges, by investment, in the simulated scenario



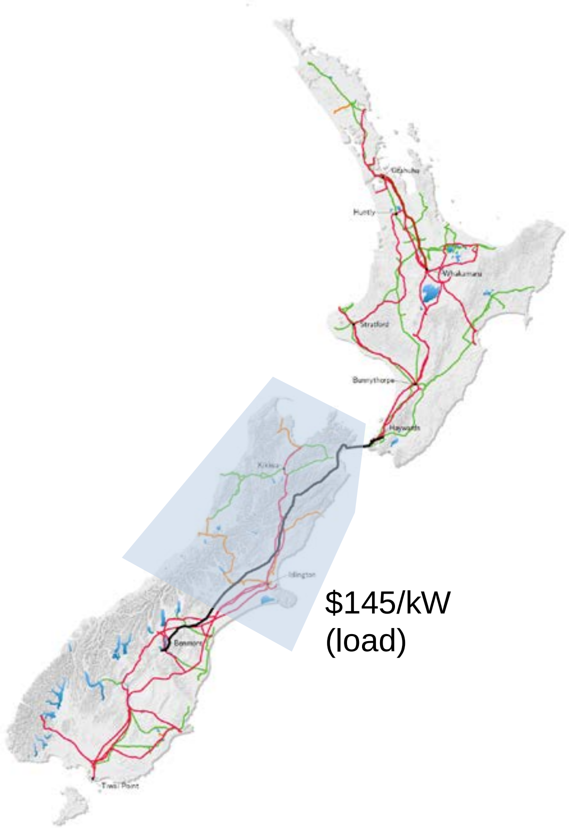
7.26 The maps on the following page (Figure 12) show the part of the country that is subject to LRMC charges for each of the investments. The rate of the simulated LRMC charge is highest in the USI.

Figure 12 Maps of LRMC in the simulated scenario (shaded areas show where charges would apply – blue for load and pink/orange for generation)

LNI transmission reinforcement



USI grid upgrade stage 2 and USI voltage stability



Residual charge

7.27 The key difference between the application of the residual charge under the Base Option and the Base Option + LRMC is the level of revenue recovered. Under the Base Option + LRMC slightly less revenue (2 percent under the modelled scenario) would be recovered through the residual charge than under the Base Option. This is because of the revenue recovered under the LRMC charge.

8 Base Option + SPD

Description of option

8.1 As Table 4 shows, the Base Option + SPD consists of seven components:

(a) LCE credit

(b) the existing connection charge

(c) a deeper connection charge

(d) a kvar charge

(e) an SPD beneficiaries-pay charge on post-2004 investments [and potentially Pole 2]

(f) an AoB beneficiaries-pay charge on post-2004 investments not covered by the above, and

(g) residual charge – postage stamp (flat rate) capacity-based charge on load.

8.2 This section addresses the SPD component. The other components are addressed in section 6.

Beneficiaries-pay – SPD charge plus area-of-benefit charge

8.3 Under Base Option + SPD, some of Transpower's MAR not recovered under the combination of LCE, the existing connection charge, the deeper connection charge, and the kvar charge would be recovered under beneficiaries-pay charges: SPD and AoB charges.

8.4 The costs of investments would first be recovered to the extent possible from beneficiaries identified through the SPD charge. The remaining costs of investments would then be recovered from beneficiaries identified through the AoB charge. This is consistent with the SPD + GIT option discussed in the beneficiaries-pay working paper.

8.5 The sequencing of SPD recovery then AoB means a lower proportion of transmission charges would be recovered from the AoB charge than under the Base Option.

8.6 The reason for considering this combination of beneficiaries-pay charges is that, unlike under the Base Option and Base Option + LRMC, the SPD charge element means the calculation of benefit is dynamic rather than static[118] and reflects the actual market outcomes rather than anticipated market outcomes. Accordingly, Base Option + SPD should result in beneficiaries-pay charges that better reflect actual benefit than under the Base Option or Base Option + LRMC. The inclusion of the AoB charge means costs of post-2004 investments (and possibly Pole 2) that would potentially be subject to the charge are fully recovered from beneficiaries rather than smeared across other parties through the residual charge.

8.7 Some of the design issues with the SPD charge raised in submissions responding to the 2012 issues paper, such as price volatility and prices being set

118 Although the AoB charge includes a mechanism to change the allocation of charges if an objective test identifies there has been a material change in the flow of benefits.

ex post, are reasonably straightforward to address, and were addressed in the beneficiaries-pay working paper.

8.8 The issues with the capping period (the maximum period over which revenue can be recovered under the SPD charge) are not so straightforward and require careful balancing.

8.9 The longer the capping period, the more the revenue that will be recovered, but the stronger the potential incentives for generators to attempt to avoid the SPD charges.[119] The Authority's preliminary assessment is that monthly capping would be optimal.[120]

8.10 The design details of the SPD charge are similar to those discussed in the beneficiaries-pay working paper:

(a) the charge for a year would be calculated ex post and applied ex ante. For example, charges calculated for the 2023 pricing year would be based on a calculation of benefits from the preceding three capacity measurement periods (on the basis that benefits would be calculated using a 3-year rolling average – see (e) below), that is, the 2019/20, 2020/21, and 2021/22 capacity measurement periods

(b) the charge would be applied to investments not covered by the connection charge, deeper connection charge, or kvar charge. The SPD charge would apply to investments approved since 28 May 2004 with a cost above $50m, and, possibly, Pole 2, and to new investments when they are commissioned with a cost above $20m. The rationale for this threshold is the same as for the AoB charge discussed under the Base Option

(c) the charging period would be one year

119 It has been suggested by some submitters that this would result in the SPD charges producing outcomes similar to a 'pay-as-offered" wholesale electricity market. The Authority considers this concern is overstated by some parties.

In a "pay-as-offered" wholesale electricity market, generators have incentives to offer generation at or near the expected clearing price, rather than at SRMC. This is discussed in Dr Brent Layton, Electricity Authority, The Economics of Electricity, 4 June 2013. Available at: https://www.ea.govt.nz/about-us/media-and-publications/media-releases/2013/5-june-2013-electricity-authority-briefing-the-economics-of-electricity/.

The SPD charge is based on the difference in private benefit between factual and counterfactual. When a generator's quantity is the same in the factual as in the counterfactual, the difference in private benefit is equal to their generation quantity, multiplied by the difference in price between factual and counterfactual. Offer price does not enter into it.

The generator's offer price can, however, affect their SPD charge, to the extent that it results in differences in their quantity between factual and counterfactual. Consider a generator that uses a transmission investment. Suppose the generator is dispatched in the factual, and not in the counterfactual. Then the difference in private benefit between factual and counterfactual is equal to their generation quantity in the factual, multiplied by the difference between the price in the factual and the generator's offer price. *(This is likely to be a relatively large number - a bad situation for the generator.)* The generator therefore has an incentive to raise their offer price as much as possible, in order to reduce the difference between the price in the factual and their offer price (and hence the difference in private benefit between factual and counterfactual, and hence their SPD charge). But there are two reasons why generators might not do this:

- because if they raise their offer price, it will make it more likely that they create a quantity difference between factual and counterfactual (and thereby make themselves worse off)

- because if they raise their offer price, it will make it more likely that they don't get dispatched in *reality*.

In short, manipulating offer prices in an attempt to avoid the SPD charge may have adverse consequences but it is not certain how large this problem would be in practice.

120 Refer to Appendix C: Choice of capping period used for the SPD charge.

(d) the SPD charge would be calculated on a net benefits only basis. This means the charge would only apply to those parties assessed as receiving net benefits – that is, positive benefits less any dis-benefits – from the investment. The charge applying to parties calculated as receiving a net dis-benefit from the investment would be zero. Charges would be calculated on the basis of net benefits over time at individual nodes but not across multiple nodes

(e) the SPD charge would be calculated according to a 3-year rolling average of the net benefits. This is to reduce year-on-year volatility in transmission charges

(f) monthly capping (see paragraphs 8.8-8.9)

(g) where demand is dispatchable, dispatchable demand bids would be used to calculate the SPD charge

(h) the price for non-supply would reflect the frequency of non-supply in the absence of the investment. Of the investments modelled in this working paper, this would mean a price for non-supply of $3,000/MWh, except for Pole 2 and OTB-HAY, which would have a price for non-supply of $1,000/MWh[121]

(i) SPD charges for distributed generation would be calculated on the basis of net injection

(j) SPD charges could be calculated at a substation level at locations where grid connected generation has been installed to supply a specific load at a separate node at the same location, provided this is efficient. Otherwise, the prudent discount policy could be designed to address this issue

(k) the minimum threshold for the inclusion of embedded generation in the SPD charge would be 10MW by scheme

(l) the Authority considers that it would be appropriate to consider net benefits to instantaneous reserves (IR) providers and to include IR dis-benefits through the spot market and through the IR cost allocation mechanism. (This, however, has not been modelled – instead a simplified approach to estimating IR net benefits has been taken.)

8.11 The changes from the proposal in the beneficiaries-pay working paper include:

(a) use of net benefits rather than gross benefits

(b) a capping period of one month rather than one day[122]

(c) charges for distributed generation would be calculated on the basis of net injection, whereas the beneficiaries-pay working paper had not reached a position on whether this should be net or gross injection.

121 In a counterfactual in which Poles 2 and 3 were unavailable, security of supply would be considerably worsened and additional peaking capacity would be needed to run at a reasonably high capacity factor. The $1,000/MWh price for non-supply in the Pole 2 and OTB-HAY counterfactual cases is intended to be a proxy for the LRMC of high-capacity-factor peaking capacity. In the counterfactuals for all other investments modelled, security of supply would be less affected and any additional peaking capacity would need to run relatively infrequently. The $3,000/MWh price for non-supply in these cases is intended to be a proxy for the LRMC of low-capacity-factor peaking capacity.

122 Refer to Appendix C: Choice of capping period used for the SPD charge.

Gross benefits versus net benefits versus net benefits with refund

8.12 In the beneficiaries-pay working paper, the Authority considered its position in relation to measuring the monetary benefit to load from assets in the SPD model. The Authority opted for gross benefits rather than net benefits or net benefits-with-refund, but this was to be subject to further review.

8.13 Examples of parties that may experience dis-benefits from a transmission investment are:

(a) a generator that faces a lower wholesale price as a result of a transmission investment (although it would be inappropriate to compensate generators for greater competition)

(b) load that faces a higher wholesale price as a result of a transmission investment (which is likely to be less common).

8.14 In submissions on the beneficiaries-pay working paper, some parties considered that charging according to gross benefit was inconsistent with promoting efficient investment.[123] This was because, in considering whether to make an investment, an investor's decision to proceed would depend on the net benefits they expected to receive from the investment – that is, positive benefits less dis-benefits.

8.15 One of the main reasons for proposing a gross benefit approach was that the Authority considered that a net benefit approach could inefficiently incentivise vertical integration. The Authority has reflected on this issue and determined that the incentive for vertical integration could occur if parties were permitted to net between locations. The Authority considered whether it was appropriate to alter netting arrangements so that parties were unable to net across different locations but could net over time. The Authority could find no material inefficiencies from allowing parties to net their positive and negative benefits over a reasonable amount of time.

8.16 Therefore, the Authority has reconsidered its position in relation to measuring monetary benefits in the SPD model. The Authority proposes that a net benefit approach be adopted if the SPD method is introduced. The Authority considers that netting over a 3 year period may be appropriate because it aligns with the 3-year rolling average proposed to smooth the volatility of SPD charges.

Restricting revenue recovered from SPD charges to the depreciated or non-depreciated value of the relevant assets

8.17 Under the modelled SPD charge, the amount recoverable in a year is restricted to the amount that could be recovered from beneficiaries to no more than the annualised costs of the investment (annualised cost cap). A component of the annualised costs of an investment is the depreciated value of the investment. The effect of this is that the amount recoverable from an investment reduces as an asset depreciates. This means that, if an asset becomes more congested over time, depreciation of that asset restricts annual charges, even though the private benefits may have increased substantively, implying there should be increased annual revenue recovery under the SPD charge.

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[123] For example, Trustpower, Trustpower submission: TPM beneficiaries-pay working paper, 24 September 2014, paragraph 5.5.3.

8.18 Unlike connection asset charges where the full annualised cost of an investment is recovered each year, the SPD charge caps revenue recovery at each party's private benefit. Given economies of scale, there is often significant excess capacity when an asset is commissioned, and thus, lower private benefit, in the initial years following commissioning. In other words, the combination of the private benefit cap and the annualised cost cap means the SPD charge under-recovers the cost of an investment over its life.

8.19 Transpower has suggested a modification to the SPD charge. Transpower has suggested to the Authority that instead of using depreciated asset value to calculate the annualised cost cap, the Authority could allow recovery based on the non-depreciated asset value. This would mean recovery for an asset under the SPD charge could increase in line with the increasing private benefit over an asset's life. The additional recovery would be realised in the later years of an asset's life. That is when private benefits are at their greatest and when a price signal to signal congestion may be efficient.

8.20 The Authority has not modelled this approach for the options working paper. However, the Authority is considering adopting this approach and seeks submitter views on whether it would be an improvement to the SPD charge.

Modelling results for the SPD charge plus area-of-benefit charge under Base Option + SPD

8.21 The parameters for modelling of the SPD charge are discussed in Appendix A.

8.22 For this options working paper, the SPD method recovers mainly economic investments because the costs of reliability investments are mainly recovered through the deeper connection charge.

8.23 The investments that are included in the calculation of SPD charges in the simulated scenario are:

(a) HVDC Pole 3

(b) HVDC Pole 2

(c) Wairakei Ring (though half the revenue requirement of this investment is modelled as being recovered through the deeper connection charge)

(d) BPE-HAY reconductoring

(e) OTB-HAY reconductoring.

8.24 The proportion of each investment's revenue requirement (less LCE) that is recovered through the SPD method is:

(a) 46 percent for HVDC Pole 3

(b) 54 percent for HVDC Pole 2

(c) 81 percent for the Wairakei Ring - for that revenue not recovered through the deeper connection charge

(d) 29 percent for BPE-HAY reconductoring

(e) 99 percent+ for OTB-HAY reconductoring.

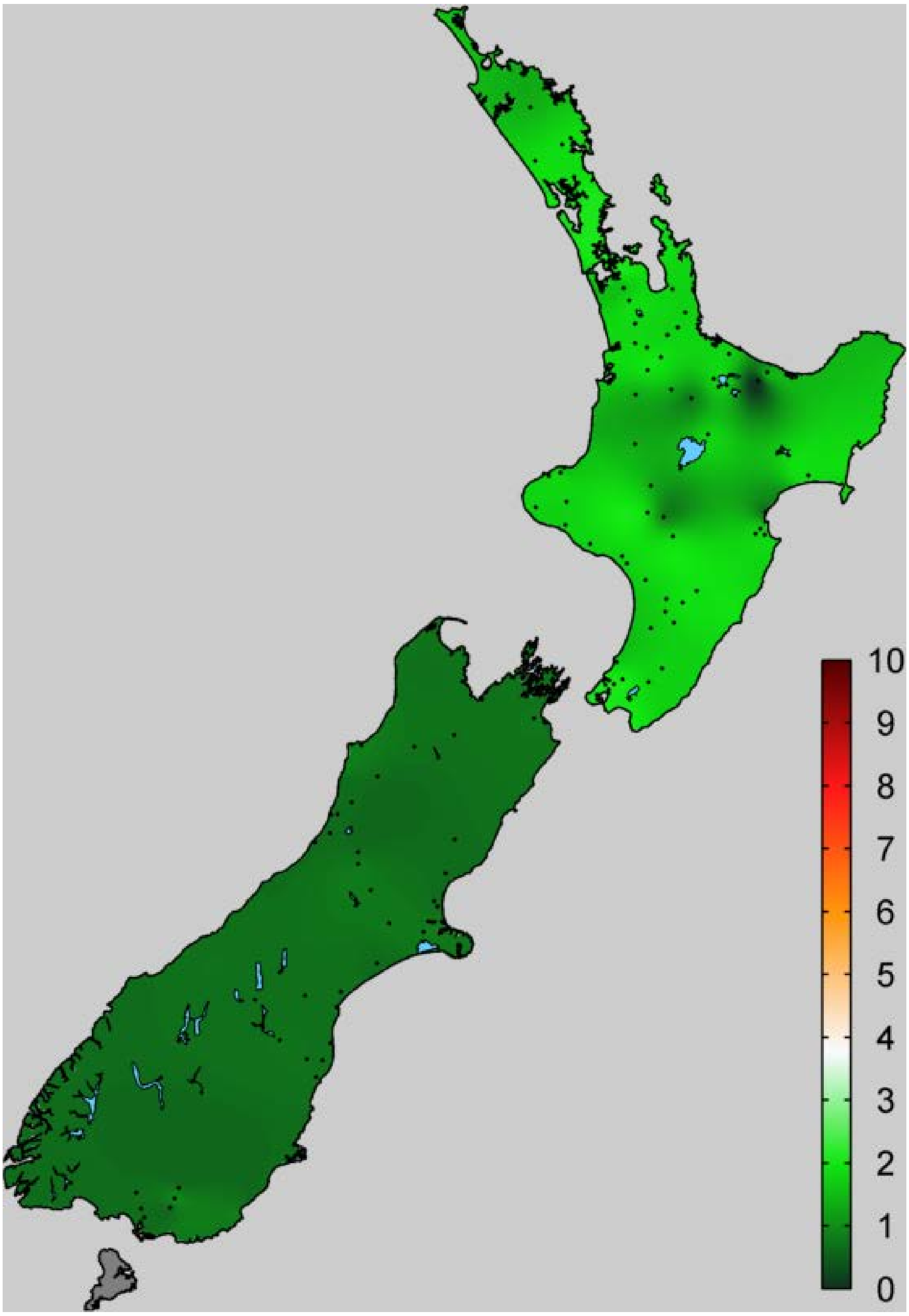
8.25 The percentage not recovered through the SPD charge would be recovered under the AoB charge.

8.26 If there were a major change in demand such as the exit of a large plant, the pattern of SPD charges could change considerably. For example, if NZAS withdrew from Tiwai, the likely effect of this would be increased power flows across the HVDC. This would be reflected in the SPD charge recovering more revenue in relation to the HVDC and any other assets affected by the change in power flows.

8.27 Figure 4 shows the distribution of SPD charges across groups of parties. In the scenario, the majority of SPD charges are recovered from North Island mass-market loads.

8.28 Figure 13 shows simulated SPD charges on load, in a 'heat map' format.

Figure 13 Incidence of SPD charges on load, in fully variabilised terms (in $/kWh)[124]



8.29 The charge is slightly higher in the NI than the SI. This reflects the benefits that NI load receives from HVDC assets and the Wairakei Ring investment.

124 This is net of LCE.

9 Evaluation of options

9.1 This section sets out a qualitative assessment of the options against the Authority's stated objective for the TPM, as well as each limb of the Authority's statutory objective. Before doing so, the Authority summarises below key aspects of the approach to the assessment.

9.2 The Authority's statutory objective in section 15 of the Electricity Industry Act is to "promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers".

9.3 Consistent with the Authority's interpretation of the statutory objective, the framework for decision making about options for the TPM should focus on overall efficiency of the electricity industry for the long-term benefit of electricity consumers. This recognises that competition is an important tool to encourage efficient outcomes and that measures that impact on reliability outcomes should encourage efficient trade-offs between the costs and benefits of reliability.

9.4 Overall efficiency refers to both efficient operation of and efficient investment in the electricity industry – the grid, generation, and on the demand-side.[125]

9.5 For the avoidance of doubt, reference to efficiency or overall efficiency includes allocative, productive and dynamic efficiency. Broadly, allocative and productive efficiency can be considered to principally promote efficient use and operation and dynamic efficiency can be considered to principally promote efficient investment.

9.6 In regard to long-term benefit of consumers, the Authority considers that its primary focus is to promote dynamic efficiency, which includes:

(a) taking into account long-term opportunities and incentives for efficient entry, exit, <u>investment</u> and innovation in the electricity industry, by both suppliers and consumers, and

(b) taking into account the <u>durability</u> of the industry and regulatory arrangements in the face of high impact low probability events. [emphasis added][126]

9.7 The discussion below provides a qualitative assessment of the three options against overall efficiency, against the statutory objective, and, finally, confirms the Authority's view that each of the options is lawful and practical.

Qualitative assessment of the options against overall efficiency

9.8 The Authority's qualitative assessment of the three options suggests each of them could potentially better promote overall efficiency and the statutory objective than does the status quo. The principal benefits are likely to be in terms of efficiency, rather than in terms of reliability or competition. Each of the options promote the Authority's stated objective for the TPM review.

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125 Electricity Authority, Decision-making and economic framework for transmission pricing methodology, Consultation Paper, 26 January 2012, paragraph 4.

126 Electricity Authority, Interpretation of the Authority's statutory objective, 14 February 2015, paragraph A11.

9.9 Table 8 provides an overview of a qualitative assessment of the options relative to the status quo. The assessment of efficiency benefits is in net terms, that is, efficiency benefits less costs, which are efficient costs.

Table 8 Overview of the qualitative assessment of the options against overall efficiency

		Base Option	Base Option + LRMC	Base Option + SPD
Efficient investment	Dynamic efficiency	✓✓	✓✓✓	✓✓✓
Efficient operation	Allocative efficiency	✓✓(✓)*	✓✓(✓)*	✓✓
	Productive efficiency	✓✓(✓)*	✓✓(✓)*	✓✓
Costs				
Establishment		Medium	Medium	Medium
Operation (Transpower)		Low	Medium	Medium
Transition (participants)		Medium	Medium	Medium
Verification (participants)		Low	Low-Mid	Medium

* The number of ✓s depends on the extent the allocation method affects incentives for efficient operation, for example, AMD may affect efficient operation but connection capacity should not.

Reasons why the Authority considers the three options better promote overall efficiency

9.10 The Authority considers that each of the three options better promote overall efficiency. The options would ensure the TPM sends efficient price signals, is more cost-reflective, is more durable and encourages greater engagement in transmission investment approval processes, all of which would lead to more efficient investment decisions.

Sending efficient price signals and ensuring better cost-reflectivity

9.11 The Authority considers that each of the options would create a stronger link between the transmission charges and the costs that are driven by use of the grid and benefits grid users receive from the grid. The costs of future grid investment, in particular, would be borne by grid-users that benefit most from the investment. More cost-reflective pricing, and a tighter link to benefits, should result in the TPM sending more efficient price signals and result in more efficient use of the grid, and more efficient investment.

9.12 The Authority agrees with the ENA that "Cost reflective … pricing structures can assist consumers to make more efficient consumption and investment decisions where electricity prices better reflect underlying costs of supply. In addition, electricity generators, transmission grid owners and distributors can make more efficient investments if consumers respond to cost reflective pricing signals"[127]

[127] ENA, Distribution Pricing: a discussion paper, 11 May 2015, paragraph 27.

and “Cost reflective pricing is fundamental for signalling efficient investments in alternative supply options”.[128]

Durability

9.13 All three options would help ensure a more durable TPM.

9.14 The options help ensure a more durable TPM by providing a link between transmission charges and the cost of providing the services that can be robustly and objectively verified, and charging parties in similar situations on the same basis. The latter has a fairness element but because it affects regulatory certainty and therefore the investment environment for the electricity industry. It therefore affects efficiency, so is a matter relevant to the Authority's decision-making.

9.15 If the options provide a more durable TPM, they would help promote more efficient investment by providing a more certain regulatory environment.

9.16 A more durable TPM would also avoid or reduce lobbying costs and, therefore, better promote efficient operation. Such costs are likely to be greatest with a TPM that results in calls for fundamental change to its design, and there is a substantial mismatch between charges and the cost of providing transmission services. Through providing charges that better match the costs of providing transmission services the options provide a more durable TPM that would avoid or reduce lobbying costs and therefore better promote efficient operation.

Engagement in transmission investment approval processes

9.17 All three options would provide strong incentives on parties to provide their views to Transpower and the Commerce Commission on whether there would be net benefits from an investment. The impact of such parties' involvement depends on the validity and relevance of the information provided, and the weighting given to that information by the Commission.

9.18 An advantage of beneficiaries-pay approaches, included in each of the options, is that if parties who would incur a substantial proportion of the cost of a grid upgrade proposal support the proposal it would send a strong signal to the Commerce Commission (and Transpower) that the proposal would have net economic benefits. The same cannot be inferred from parties that support an investment that they would not pay for, or where the cost is substantially smeared over other users. For this reason, beneficiaries-pay charges can help support the discovery of efficient transmission investment through the investment approval process.

The remaining components of the statutory objective: reliable supply and competition

9.19 The Authority has interpreted the reliable supply limb of the statutory objective as meaning the efficient level of reliable supply.[129] In particular, the Authority has interpreted the reliable supply limb as “exercising its functions in ways that encourage industry participants to efficiently develop and operate the electricity system to manage security and reliability in ways that minimise total costs whilst

128 ENA, Distribution Pricing: a discussion paper, 11 May 2015, paragraph 42.

129 Electricity Authority, Interpretation of the Authority’s statutory objective, February 2011, paragraph A.47.

being robust to adverse events."[130] This means that reliable supply relates to both efficient use and efficient investment. The Authority considers that each of the options would help better promote efficient use and investment.

9.20 Each of the options would set charges for transmission services on a more consistent and cost-reflective basis, and would better promote competition by ensuring generators in particular are able to compete on a more level playing field. Further, all three options limit support of investment or operation of generation to avoid transmission costs except to those areas where transmission investment is anticipated. This also helps ensure that generation is able to compete on a more equal basis, regardless of whether the generation is grid-connected or not.

Determining which option would better promote the statutory objective than the other two

9.21 The Authority has not formed a view on which of the three options should be preferred. Submissions on this options working paper will help the Authority to form a view on which of the options would better promote the Authority's statutory objective compared with the others, and whether an alternative or combination thereof may better promote the objective. The quantitative CBA that will be undertaken when developing the second issues paper will also help identify the preferred option and application.

9.22 Given each of the three options has the same base (revised treatment LCE, kvar charges, connection, deeper connection, AoB, and residual charge), which options should be preferred depends on whether an LRMC (Base Option + LRMC) or SPD (Base Option + SPD) charge would provide incremental net benefits in addition to the Base Option. Put another way, are LRMC or SPD charges complementary to the design of the Base Option?

Dynamic pricing signals

9.23 An LRMC charge would provide a price signal directly linked to the cost of future investment on parts of the grid that become capacity constrained, and where further investment may be required. This would provide an incentive on parties to directly take into account the transmission cost implications of their demand for transmission services.

9.24 Once the investment is made, the LRMC charge would drop away, but the AoB charge would increase reflecting the cost of the new investment in the area. The AoB charge would help ensure the timing of investments is efficient as it would counteract any incentives provided through the LRMC charge for parties to seek to have the investment brought forward in order to limit their payment of that charge.

9.25 The ENA considers that "An LRMC charge would provide transmission users with price signals that approximate the long run costs of their transmission usage at peak times" and that "This is desirable from a dynamic efficiency perspective".[131] The extent to which LRMC charges would be dynamically efficient also depends

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[130] Electricity Authority, Interpretation of the Authority's statutory objective, February 2011, paragraph A.48.

[131] ENA, Submission on Transmission Pricing Methodology: Beneficiaries-pay options, 25 March 2014, paragraph 46.

on the extent to which it would influence investment and consumption decisions, and on how reliably the LRMC can be calculated. The vagaries of transmission investment planning may make reliable calculation of LRMC charges difficult to achieve in practice.

9.26 The Authority raised concerns in the LRMC working paper,[132] about whether robust estimates of LRMC can be produced that could be relied on for transmission pricing purposes. The Authority continues to hold these concerns.

9.27 Including an LRMC charge could affect Transpower investment planning and forecasting since these would have direct implications for parties' charges. This would provide incentives on Transpower's customers to pressure Transpower to either understate its intended investments or delay inclusion of investments in its forecasts or both. Acting against this incentive, however, would be the Commerce Commission's investment approval regime (which includes a requirement for Transpower to publish an integrated transmission plan), and clause 12.76 of the Code. Clause 12.76 requires Transpower to publish a grid reliability report, including proposals to address reliability issues.

9.28 The LRMC charge is unlikely to recover a large portion of Transpower's revenue requirement initially, which is reflected in the small amount of revenue it recovers (see Figure 1). However, this could change in the future as demand for transmission services grows.

9.29 If an SPD charge was introduced, it would have a more prominent role than LRMC, collecting a substantial amount of the revenue that would otherwise be recovered by the AoB charge.

9.30 Another key difference between an LRMC and an SPD charge is that the LRMC charge applies, ex ante, before the transmission investment occurring, while an SPD charge would apply, ex post, after the transmission investment has taken place. This means LRMC provides a more direct pricing signal of the cost of future investment. The beneficiaries-pay charges (AoB, under Base and Base + LRMC, or AoB and SPD under Base + SPD) provide an indirect signal for market participants to take into account future transmission cost implications of their investment and usage decisions. The beneficiaries-pay charges set a price based on actual cost which could differ (higher or lower) to an LRMC charge.

9.31 The attraction of an SPD charge is that it provides an objectively measurable way of determining the economic benefits parties receive from transmission investment through the wholesale electricity market. The measurement of benefit is done on a dynamic basis (based on half-hourly wholesale electricity market outcomes) so can better reflect actual benefits than reliance on AoB under the Base Option and the Base Option + LRMC.

9.32 The Authority has addressed many of the concerns raised by stakeholders with the original SPD proposal, such as the volatility of the charges, and that they would not be known in advance.

9.33 A critical factor in relation to the benefit of SPD charges is the extent to which market participants would be able to successfully game the wholesale market to

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132 Electricity Authority, Transmission Pricing Methodology Review: LRMC charges, working paper, 29 July 2014, sections 7 – 9.

avoid the SPD charges. If this happened, it would affect nodal prices and the efficient operation of the grid.

Durability

9.34 Of the options, the Base Option and the Base Option + SPD provide a demonstrable relationship between the service provided from an investment and the charge faced by parties (and parties in similar situations are charged on the same basis) which assists with durability. The SPD charge could also make the TPM more durable as this charge tracks the benefit different parties receive from an investment over time in an objective and verifiable manner. The Base Option + SPD's durability would be undermined if generators were successfully able to, or are perceived to be able to, game their generation offers in a way that avoided or reduced their SPD payments, for example by offering generation close to the expected clearing price, rather than at SRMC.

9.35 The Base Option can also track changes in benefit received by different parties by allowing for changes to the allocation of the deeper connection and AoB charges, but only the SPD charge automatically adapts to changes in use of the grid over time. The SPD charge could become the default approach if a revised AoB charge was too difficult to determine.

9.36 The durability of the Base Option + LRMC may be undermined by the volatility of the LRMC charge, as compared with the non-volatile AoB charge and the smoothed SPD charge (through applying this on a rolling average basis) under the Base Option + SPD. While the volatility of the LRMC charge is intentional – as it is intended to reflect how changes to demand for transmission services affect the timing of a transmission investment – parties subject to the charge may nevertheless see this volatility as undesirable and seek to have the charging regime changed.

9.37 The durability of the Base Option + LRMC would also be affected by the robustness of the transmission investment information used to calculate the charge. The Authority understands that this has resulted in debate about the LRMC charges that apply in the UK.

9.38 Also, as discussed in the LRMC working paper, the LRMC charges are on the basis of the cost of the future investments required to meet changes in demand. However, because the Part 4 Commerce Act regime only allows Transpower to charge for assets once an investment has been commissioned (or is forecast to be commissioned within a pricing year), the costs of an investment still have to be recovered ex-post. This is less of an issue when the costs of an investment are recovered on an adjusted beneficiaries-pay basis as proposed. However, some parties may still see this as double recovery, which may affect the durability of this option. Against this though, revenue recovered through the LRMC charge can offset other charges.

Operation cost, transition and verification

9.39 Once established, the Base Option should involve low operation costs for Transpower. This is because the deeper connection charges could be set for 5 years before being re-calculated, the application of the AoB charge is set in advance, and the allocation of charges among parties uses straightforward methods, for example per MWh for generation and capacity-based for load. The only additional operation cost would be applying the proposed objective test under the AoB charge for determining whether the beneficiaries of investments subject to this charge had changed, but this should only involve moderate operation costs.

9.40 The Base Option + LRMC would involve more operation costs for Transpower because investments and demand would need to be forecast, although it is proposed to use an existing forecast rather than require a new one. Transpower would also need to estimate the LRMC charges each year. The costs of operation of other charges would be similar to the Base Option.

9.41 The Base Option + SPD would also involve more operation costs for Transpower because of the need to calculate the SPD charge. The Authority is considering calculating and publishing benefits estimated through the SPD method. If this were done, the incremental costs of implementing the SPD charge would be lower than has been previously assumed.

9.42 Since it is proposed that the SPD charge be applied on a rolling average basis with the rolling average used to set the charge for the following year, this calculation need only be performed annually. The costs of operation of the other charges would be the same as the Base Option, except the AoB charge would need to be recalculated as the SPD charge would vary.

9.43 All three options would involve some transition costs for participants because they would need to familiarise themselves with the new charges.

9.44 The costs of verifying charges should be low for the Base Option if all charges except the kvar charge are calculated according to capacity to the extent possible.

9.45 The costs of verifying charges for participants for the Base Option + LRMC should be low to medium depending on whether participants were subject to an LRMC charge or not. Verification of the LRMC charge should be straightforward once participants are familiar with calculation of the charge, although participants would need to have confidence in the cost information used to calculate the charge. Verification of other charges under the Base Option + LRMC should be straightforward because the charge would be calculated according to capacity, to the extent possible (except for the kvar charge).

9.46 The costs of verifying charges for the Base Option + SPD would be higher than the Base Option, as it would require understanding of the SPD charge, which may require external expertise, at least at first. The costs of verifying other charges should be the same as the Base Option.

Assessment of lawfulness and practicability of options

9.47 The Base Option, Base Option + LRMC and Base Option + SPD are all lawful.

9.48 The Authority's preliminary view is that the practicability issues with all three options can be addressed, but the Authority will consider feedback on this working paper and undertake further analysis. The Authority's experience from modelling these options for presentation in this working paper suggests all options should be practicable.

9.49 Potential practicability issues common to all three options are:

(a) calculating the kvar charge. In particular, this charge has yet to be modelled on the basis of the power factors currently prevailing in the grid

(b) calculation of the deeper connection charge. This working paper and the companion paper discuss proposals for how the deeper connection charge would be applied but the operational details would still need to be determined

(c) calculation of the AoB charge. This includes developing a robust and consistent basis for determining the area expected to benefit from a transmission investment. This working paper has provided a demonstration of how this might be done, but this would need further refinement to apply the AoB charge in practice. However, the fact that AoB charges are applied by some United States transmission operators, such as the Mid-west Independent System Operator (MISO), suggests this is a practicable charge. In addition, the objective test for determining whether the beneficiaries of investments subject to this charge had changed would need to be developed

(d) calculating the capacity-based residual charge for load. The key practicability issue here is identifying an efficient means of applying the residual charge to direct connect customers on a capacity basis. This working paper has modelled the application of this charge on the basis of AMD, but this may affect operational efficiency.

9.50 The Authority's modelling demonstrates that the Base Option + LRMC is practicable although design details for the calculation of the LRMC charge would need to be worked through. This working paper has proposals for most of the practicability issues identified with applying LRMC charges in the LRMC charges working paper[133] although the operational details of applying the LRMC charge would still need to be determined.

9.51 The key practicability issues for the Base Option + SPD are the same as for the Base Option except for calculation of the SPD charge. The beneficiaries-pay working paper identified the following practicability issues for calculating the SPD charge:

(a) Specification of the SPD method: this working paper has proposals for how this would be done.

(b) Calculation of security constraints to be used as an input to calculating the charge if a party other than Transpower was allocated the role of applying the SPD method. Transpower uses the simultaneous feasibility test (SFT) for this task.

133 Refer to: Electricity Authority, Transmission Pricing Methodology Review: LRMC Charges working paper, 29 July 2014, pages 36-38.

(c) Ensuring sufficient time and computational resources were available for application of the charge.

9.52 In addition, the Authority may wish to make operation of the SPD method contestable. If this were done, the practicability issues would include establishing a new service provider and establishing arrangements to provide results to Transpower, so it could calculate the SPD charge.

10 Price effects of the options

10.1 All of the options involve introducing several new charges, which in aggregate would significantly change transmission charges for some parties, particularly in relation to Application A.[134] Parties that are anticipated to incur higher charges are generally parties that receive the benefits of the recent transmission investments.

10.2 Transmission charges would increase in the UNI where the majority of investment over the last decade has occurred, and in some other locations such as the West Coast and Marlborough. North Island generators, who presently do not contribute to HVDC or interconnection charges, would also bear higher transmission charges.

10.3 The proposals would result in lower transmission charges for consumers in regions such as Christchurch, Hawkes' Bay, Southland, Wellington and parts of the central North Island. Meridian and Pioneer would also incur lower transmission charges, as would most direct connection industrial consumers.

10.4 To provide a sense of the magnitude of the change in charges under each option, Figure 14 shows the modelled annual change in charges (excluding the kvar charge, connection charges and LCE credit) to generation and load relative to the status quo for each option. Figure 14 provides a modelled breakdown of revenue received under each option from each group of consumers of transmission services. Bar charts are provided to illustrate the options against status quo charges based on $M per year, $/ICP per year and $/MWh per year.[135]Figure 15 shows the modelled regional incidence in charges relative to the status quo in variabilised terms.

10.5 All figures are based on an assumption that generators do not pass through any charges.[136] These figures do not anticipate how participants might react to changes in charges or what the consequences might be. This is a matter that will be considered as part of the quantified CBA in the second issues paper. Nor do the figures show how the choice of the HHI value to determine assets recovered through the deeper connection charge affects deeper connection charges[137] or how the choice of capping period affects SPD charges[138] – nor does it provide variants of the three options with different residual charges.

10.6 All key results are shown for an entire 3-year period, rather than for individual years.

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[134] Refer to Appendix E for estimated changes in total transmission charges to individual parties and Appendix F for an indication of the effect of the options on residential electricity prices.

[135] Appendix E provides a detailed breakdown of the simulated incidence of charges under each of the three options.

[136] Appendix E provides simulated charges on load under each of the three options (including status quo), which includes the effect of uplift in energy prices as a result of generators passing on transmission charges they incur.

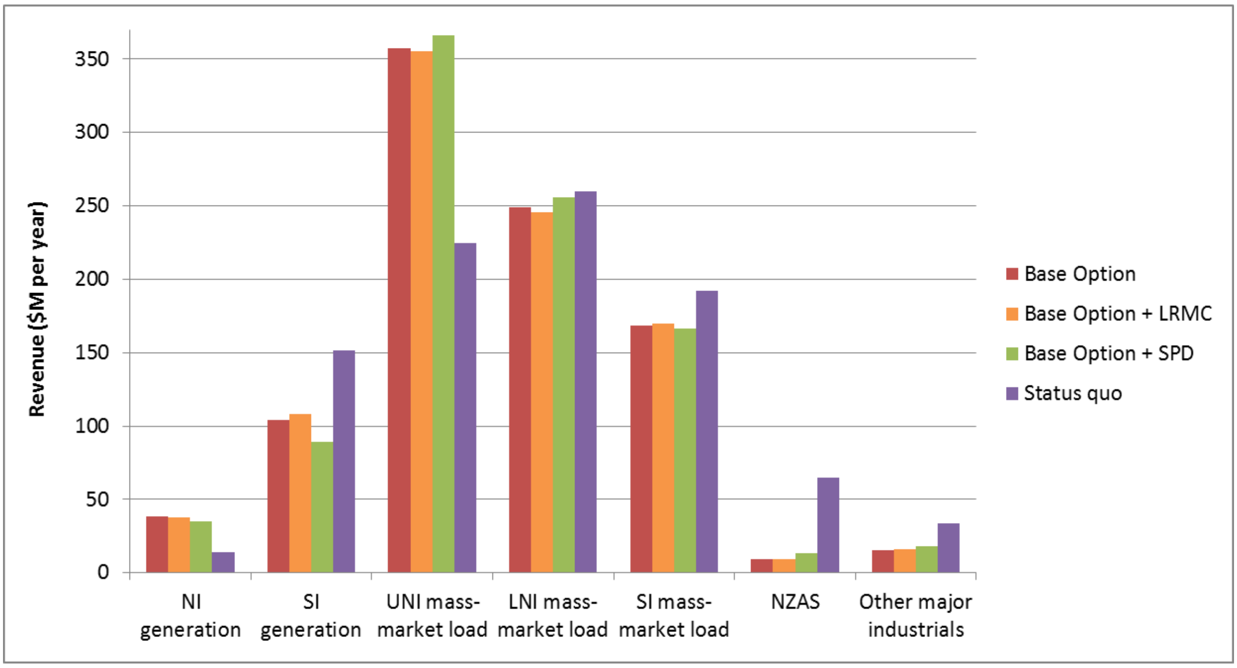
[137] Refer to: Electricity Authority, Options Working paper: companion paper describing the detail of the deeper connection charge, June 2015, Appendix B.

[138] Refer to Appendix C.

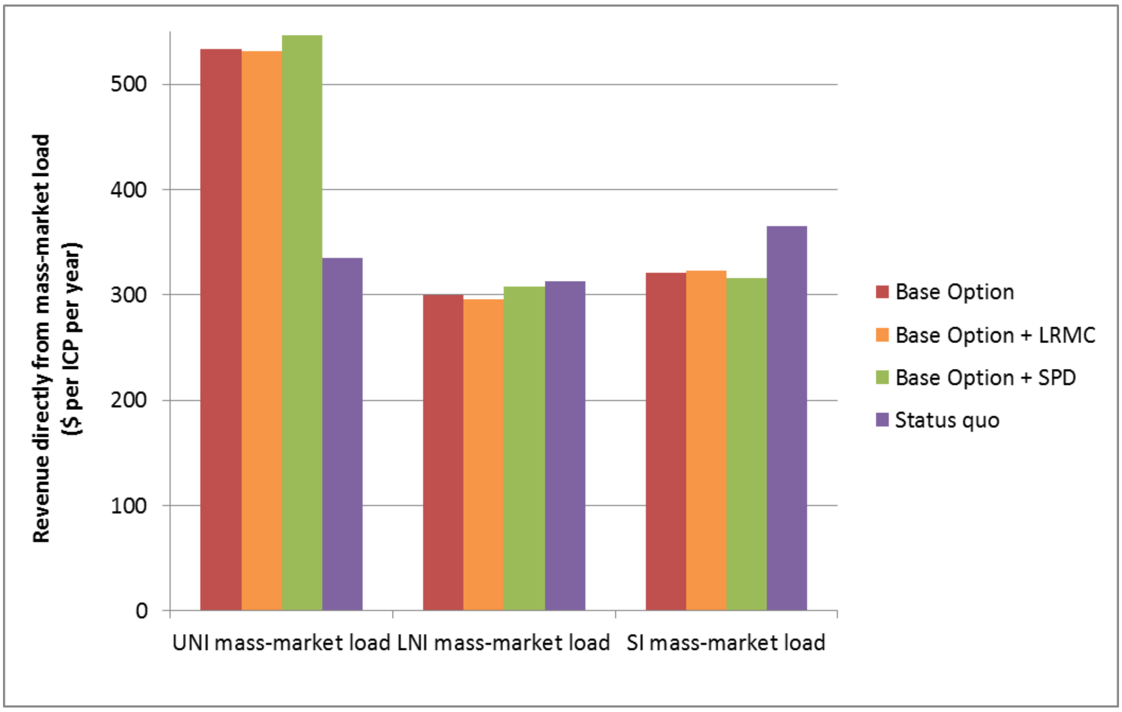
10.7 Figure 14 shows that, under all options, charges to UNI mass-market load and NI generation would increase relative to the status quo, while charges to LNI mass-market load, SI mass-market load and major industrial consumers would fall.

Figure 14: Breakdown of options by cost allocation to groups

A. Charges in $M per year

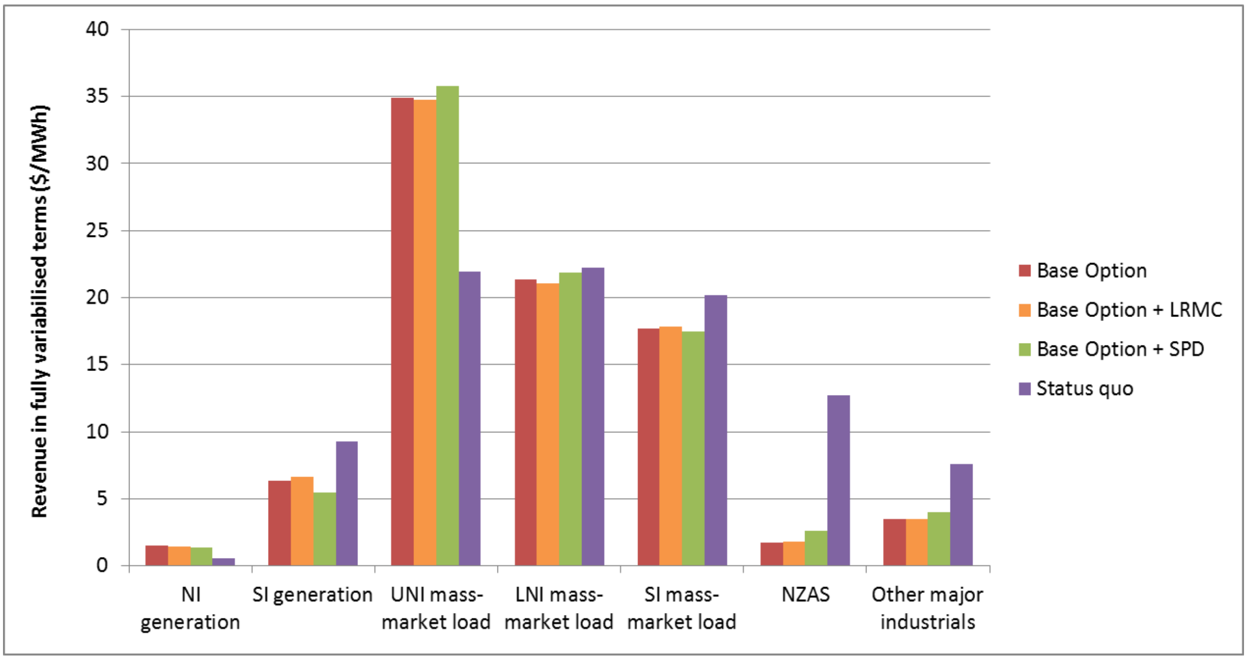


B. Charges in $/ICP per year (mass market load only)



Note: The figures in plot B above represent the charge on the EDB divided by the number of active ICPs. Because they are averaged across both residential and commercial ICPs, they are likely to exceed the charge on a typical residential ICP.

C. Charges in $/MWh



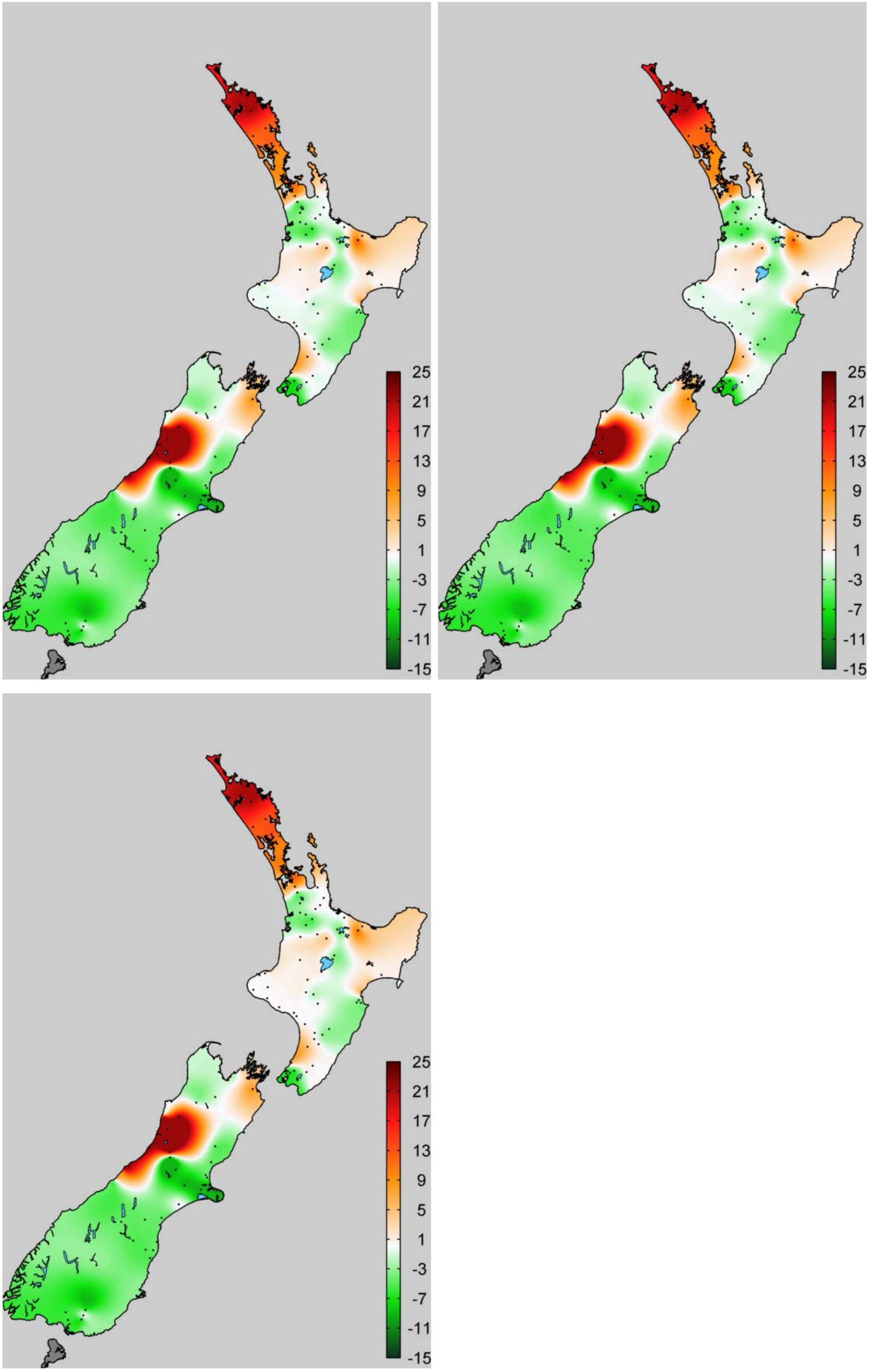
Note: The figures in plot C above represent:

- *charge divided by generation injection, for generators*
- *charge divided by load offtake, for major consumers*
- *charge divided by approximate gross electricity consumption, for distributors pooled across three regions of the country.*

10.8 Figure 15 shows that transmission charges would increase in some regions, notably the West Coast and upper North Island, but decrease in other regions – including Canterbury and the lower South Island, Wellington and parts of the central North Island.[139]

139 Appendix D provides simulated charges on load under each of the three options (relative to status quo), in a 'heat map' format. The heat maps in Appendix D differ from Figure 15 as they include the effect of uplift in energy prices as a result of generators passing on transmission charges they incur.

Figure 15: Regional incidence of charges under the Base Option (top left), Base Option + LRMC (top right), and Base Option + SPD (below left), relative to the status quo, in variabilised terms (all $/MWh)



Offsetting benefits from transmission investment should also be considered

10.9 In considering the effects on transmission charges from the three options, it is important to note that parties that could experience increased transmission charges as a result of recent transmission investments also receive benefits from these very investments that would offset the costs of increased charges. In particular, load parties benefit from cheaper wholesale electricity prices and improved reliability while generators benefit through improved prices and an improved ability to sell electricity to other regions.

10.10 Table 9 illustrates the change in the location factor, which reflects the impact of losses and constraints on nodal prices, in relation to recent large investments for periods before and after the investment. Table 9 also illustrates the change in the frequency of significant price separation[140] that resulted from these investments.

Table 9: Change in location factors and frequency of price separation resulting from recent transmission investments

Investment	**Wairakei Ring**	**NIGU**	**NAaN**
Commissioning date	Jul 2014	Nov 2012	Feb 2014
Comparison is between:			
- pre period	Jan 2012 – Dec 2013	Jan 2010 – May 2012	Apr 2012 – Aug 2013
- post period	Aug 2014 – Feb 2015	Dec 2012 – Feb 2015	Mar 2014 – Feb 2015
Key location factor	Whakamaru / Wairakei	Otahuhu / Whakamaru	Marsden / Otahuhu
Median location factor (%):			
- pre period	102.3%	104.4%	102.3%
- post period	100.6%	102.4%	101.8%
- reduction	1.7%	2.1%	0.5%
Frequency of significant price separation (%):			
- pre period	0.52%	0.32%	-
- post period	-	-	-

10.11 The analysis suggests that the Upper North Island has received a 3.8 percent reduction in spot prices through the reductions in transmission losses resulting from Wairakei Ring and NIGU,[141] and that the area north of the isthmus has

140 'Price separation' refers to differences between wholesale electricity prices at different nodes on the transmission grid.

141 The 3.8% reduction in spot prices for the UNI is calculated by summing the reduction in the median location factors for the Wairakei Ring (1.7%) and NIGU (2.1%).

received a further 0.5 percent reduction in spot prices, through the reductions in transmission losses arising from NAaN.[142]

10.12 As a result of loss reduction, the UNI receives a private benefit estimated at approximately $20M per year (assuming the UNI's total electricity consumption is 8 TWh per year, and the mean spot price is $70/MWh).

10.13 The analysis also suggests that the frequency of price separation between Wairakei and Auckland has dropped from about 0.8 percent to near nil, due to Wairakei Ring and NIGU preventing constraints from occurring. The area north of the isthmus was not significantly affected by constraints, either pre or post NAaN.

10.14 As a result of avoiding higher prices during constraints, the UNI receives a further private benefit estimated at approximately $12M per year (assuming the UNI's total electricity consumption is 8 TWh per year, and that the average price separation in constrained periods would be $200/MWh).

10.15 The total private benefit to the UNI, estimated as $32M per year ($20M for loss reduction and $12M for lower prices), is less than the combined annual cost of the three transmission investments (which is well in excess of $100M per year), but is by no means negligible.

10.16 It should be noted that the 'pre' periods may have been affected by either outages or increased losses or both as a result of the construction of the investments. If these occurred, these estimates of private benefits would be overstated.

10.17 In addition to the wholesale market benefits from transmission investment illustrated by this investment, it is also important to consider the reliability benefits from transmission investment.

Reliability benefits to the region

10.18 Most major transmission investments approved since 2004 were reliability investments. The main expected benefit from reliability investments is a reduction in the value of unserved energy. Reliability investments reduce the quantity and duration of supply interruptions on the network.

10.19 Reliability benefits generally accrue to particular regions, or they accrue to the parties for whom transmission investments were undertaken to serve. Thus reliability benefits offset cost reflective transmission charges.

10.20 Reliability benefits can be considerable, partly because some customers place a high value on service reliability. However, actual reliability benefits can be substantially lower than expected reliability benefits, particularly where future demand is overestimated.

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142 The further 0.5% in reduction in prices north of the isthmus is just the median location factor for NAaN (0.5%).

11 Potential application of new charges under options

11.1 The Authority recognises the view expressed by a number of parties, in response to the 2012 issues paper, that any new charges targeting promotion of efficient investment should apply only to new assets. The Authority also recognises that the three options it is considering could result in large changes in the allocation of transmission charges between parties, compared with the status quo.

11.2 As a consequence, the Authority is considering two possible applications of the new charges proposed under the three options:

a) Application A: This would involve applying new charges to both existing and new assets and investments

b) Application B: This would involve applying new charges to recover the costs of new assets/investments only, with all other costs recovered through the existing charges, that is, the connection, interconnection and HVDC charges.

11.3 The detail of how these applications might be applied to the charges under the three options is set out in Table 10.

Table 10: Possible applications of charges

Charge	**Option**	**Application A** **(New charging methods apply to both existing and new assets and investments)**	**Application B** **(New charging methods apply only to new assets[143])**
LCE Credit	All options	Apply to all existing and new investments	Same as Application A
Connection charge	All options	Apply as now	Same as Application A
Deeper connection charge	All options	Apply to all eligible existing and new assets	Apply only to new assets
LRMC charge	Base Option + LRMC only	Applies in respect of future investments only	Same as Application A
kvar charge	All options	Based on the cost of future investments to	Same as Application A

143 For the purposes of Application B, "new" assets/investments would be assets upgraded, constructed or replaced with commissioning date falling after the Authority published revised TPM guidelines.

Charge	Option	Application A (New charging methods apply to both existing and new assets and investments)	Application B (New charging methods apply only to new assets[143])
		provide static reactive support	
SPD charge	Base Option + SPD only	Apply to post-2004 investments above $50m, post guideline investments above $20m, and, potentially, HVDC Pole 2	Apply only to new investments
Area of Benefit (AoB) charge	All options	Apply to post-2004 investments above $50m, post guideline investments above $20m, and, potentially, Pole 2	Apply only to new investments
Residual charge	All options	Apply capacity-based charges[144] to recover residual revenue[145]	Recover residual HVDC revenue through current HVDC charge.[146] Recover remaining residual revenue through current interconnection charge,[147] with one exception. The exception is that all load customers must pay at least the variable cost arising from their connection to, and use of, interconnection assets.

144 That is, the allocation is based on ICPs for most consumers and based on AMD for industrial consumers.

145 Residual revenue = Transpower's total revenue requirement less revenue collected from above charges.

146 Subject to changes the Authority may approve as part of the review of Transpower's TPM Code Amendment Proposals 2015.

147 Subject to changes the Authority may approve as part of the review of Transpower's TPM Code Amendment Proposals 2015.

11.4 Several considerations are important when determining the relative efficiency of the two applications.

11.5 First, a sizable portion of the dynamic efficiency benefits from the options would arise from applying new charging methods to new investment. This is because, as a number of submissions have pointed out,[148] it gives parties the opportunity to respond to the charges before the investment is made, including through the transmission investment approval process. It is this response and the consequential changes to investment that gives rise to the dynamic efficiency gains.

11.6 However, that is not to say that no dynamic efficiency gains are obtainable from applying new charges to existing assets. Applying new charges to existing assets can help promote more efficient investment if the charges help improve the quality of future investment decisions. For example, if a charge provides better information about the cost of consuming transmission services, consumers are better informed for their own decisions about investing in alternatives, for example investments that would allow a consumer to go off grid. For this reason, it is also important to consider Application A in addition to Application B.

11.7 Second, Application A would potentially result in large changes to charges, which would largely be avoided under Application B. However, the changes in charges under Application A would reflect a move to a more cost-reflective pricing. This is because it would remove any mismatch between current charges and the cost of delivering transmission services that may have accumulated over time.[149] Application B would preserve the existing imbalances in cost allocation discussed in the problem definition section.

11.8 Third, and following from the second point, under Application B, parties receiving the benefit of new investments would face the new charges for these investments but would also have to contribute to the costs of historical investments through the existing charges. For example, significant transmission investment is expected to be needed in the USI. Under Application B, USI customers would have to pay for this and, also, contribute to the costs of the recent investments in the UNI, but UNI customers' charges would not change. This may adversely affect both efficient investment (including through threatening the durability of a change to the TPM) and use.

11.9 Fourth, to the extent that the proposed new residual charge would more efficiently recover revenue than the current interconnection charge, which is in effect the residual charge under the status quo, it is likely that these efficiency gains can only be obtained under Application A. This is because residual revenue arising under Application B would be recovered under the current interconnection charge. New residual revenue arising under Application B would be confined to base capex (investment less than $20m) not covered by the AoB charge under the Base Option and Base Option + LRMC, or the SPD charge and AoB charge under Base Option + SPD.[150] In addition, the LRMC charge under

148 For example, MEUG submission on the problem definition working paper, p.10/11.

149 Refer to: Section 4, Summary of the Authority's current views on problem definition.

150 Note that the kvar charge would also offset the need to recover some residual revenue under all options.

Base Option + LRMC would offset the need to recover some of this new residual revenue under that option.

11.10 Fifth, to the extent that there are inefficiencies from the existing charges, these would erode only gradually under Application B but would be eliminated from the outset (subject to a transitional regime) under Application A.

11.11 Sixth, the status quo charges have not been designed to be applied in conjunction with the new charges. Accordingly, there would be price signals from both the new and existing charges under Application B that may interact in unintended ways. For example, as well as the price signals for more efficient investment from the deeper connection, kvar and AoB charges (and LRMC or SPD), there would also be a signal to avoid peaks under the current RCPD interconnection charge. This may result in excessive signals to curtail demand. Accordingly, if Application B were implemented it may be appropriate to alter the parameters of existing charges. This may be an issue for consideration in the second issues paper.

11.12 Under both applications, the Authority would need to draw a "line in the sand" to determine the assets that would have their revenue recovered by the proposed dynamic (beneficiaries-pay and LRMC) charges.[151] Under Application B, a line in the sand would also be required for application of the deeper connection charge. The Authority acknowledges that, to a certain extent, the line in the sand may be arbitrary and require trade-offs.

11.13 The Authority's preliminary view is that Application A is likely to yield greater net benefits. The Authority would welcome submitters' perspectives on whether they consider this would be the case. Issues with price increases would be best dealt with through transition mechanisms.[152]

11.14 Ultimately, the decision on which of Application A or B should be preferred would come down to cost-benefit analysis. The Authority would welcome submissions to help inform this.

Details of Application B

11.15 Application B raises specific issues about how it would be applied.

<u>Application of LCE credit under Application B</u>

11.16 The proposed approach to application of the LCE credit under Application B is consistent with Application A. That is:

a) LCE attributable to an individual connection asset or deeper connection asset would be credited against the charges of customers that pay for that asset

b) LCE not attributable to connection or deeper connection assets would be credited in bulk against Transpower's remaining maximum allowable revenue.

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151 The Commerce Commission was in a not dissimilar situation when it was developing the RAB IM under Part 4 of the Commerce Act. It choose to set the asset valuations for electricity and gas networks on the basis of 2004 optimised deprival values (ODVs), for investments up to 2004, (the "line in the sand") with subsequent investment added to the RAB at actual cost.

152 Refer to: Section 12, Potential transition alternatives.

11.17 However, since Application B involves continuing the existing charges for existing assets, it is important to specify how LCE arising on these assets would be allocated.

11.18 First, as is the case under Application A, LCE arising on connection assets would be credited against the connection charges for the assets on which the LCE arose.

11.19 For assets subject to HVDC and interconnection charges, there are two possible options:

i. continue with the status quo approach of applying the LCE arising on these assets according to Transpower's rental guides

ii. apply the same approach as under Application A, that is, credit LCE not attributable to connection or deeper connection assets against Transpower's remaining MAR.

11.20 The key difference is that (i) in effect involves separate allocation of HVDC and interconnection LCE whereas (ii) pools the LCE from both assets.

11.21 Given that over time fewer and fewer costs would be recovered under historical charges under Application B (although the long-lived nature of transmission assets mean this will occur over a prolonged period), it is proposed that (ii) will apply rather than (i). This would ensure that the allocation of LCE is consistent for assets subject to new and historical charges. This would also simplify the allocation of LCE. However, leaving aside the effect of the introduction of new charges, interconnection and HVDC charges in net terms (that is, taking into account the LCE) may differ from the status quo.

<u>Application of deeper connection charge under Application B</u>

11.22 In relation to the deeper connection charge, under Application B it would be necessary to determine what constituted a 'new' asset. It is proposed that refurbishment and replacements of, and upgrades to, existing assets undertaken as part of a major capex proposal (as defined in the Capex IM) and commissioned from the date that revised or replacement TPM guidelines were put in place, would constitute 'new' assets.

11.23 In addition, in situations where a refurbishment, replacement, or upgrade resulted in a mixture of new and existing assets (for example new conductors were added to existing towers), there is the question of whether, under Application B, the deeper connection charge would only apply to the new assets. It is proposed that where this occurs, the deeper connection charge would apply to all assets caught by the deeper connection charge threshold. This would mean that where, for example, new conductors were added to existing towers both would become subject to the deeper connection charge. This would simplify charging somewhat and would mean broad application of the deeper connection charge would occur over a shorter period, which would allow quicker access to the efficiency gains from the deeper connection charge. It would also avoid introducing an incentive for parties to lobby to avoid replacement of old assets.

<u>Application of AoB charge under Application B</u>

11.24 Under Application B, the AoB charge would be applied to 'new' investments only. As for Application A, it is proposed to define new investments as investments over $20 m approved after the date of publication of the guidelines. This would allow parties to incorporate new charges on new investments into their own investment decisions. The rationale for proposing that new investments includes those approved after the date of publication of the guidelines is that parties potentially have the ability to influence the commissioning date and therefore investment efficiency.

Application of residual charges under Application B

11.25 The proposed new residual charge would not apply under Application B. "Residual revenue" (that is, revenue not recovered through new charges) would be recovered through the HVDC charge for the current HVDC assets and the interconnection charge for historical interconnection assets. As noted in paragraph 11.9 some new residual would arise under Application B because it is proposed that the AoB charge would only apply to new investments greater than $20 m. Since this is not expected to be a large amount[153] it is proposed to recover this under the existing interconnection charge.

11.26 It is proposed that, under Application B, the calculation of charges and the parties to which charges would apply would be the same as under the status quo (or a modified status quo as a result of Transpower's TPM operational review).

11.27 However, it is proposed these charges would be altered so that all load customers must pay at least the variable cost arising from their connection and use of interconnection assets. Variable costs include Transpower's maintenance costs, operating costs and overhead. Under the status quo, generators contribute to Transpower's overhead costs through the connection charge but connection charges to load customers do not include an overhead component as this is expected to be recovered through the interconnection charge. To the extent that load parties are able to avoid paying the interconnection charge by avoiding net consumption during the RCPD periods used to apply the charge, they avoid paying for variable interconnection costs and for overhead. If parties are paying less than the variable costs of providing them with connection and interconnection services, this would mean that they are paying less than the short-run marginal cost (SRMC) of the service, which would be inefficient. Requiring parties to at least pay SRMC would be efficient as it would mean they would face the correct signal as to whether to continue to consume the service or not.

11.28 Introducing this requirement would necessitate determining what share of variable costs should be recovered from each customer. The Authority proposes that variable costs currently recovered through the interconnection charge[154] would be allocated pro rata on a gross MWh basis (that is, ignoring embedded generation) across load customers. Load customers would have to pay at least their MWh share of these costs.

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153 Note that the deeper connection charge would apply to applicable base and major capex, as is the case with the connection charge. This means that base capex not covered by the AoB charge should be relatively small.

154 The Authority understands that the variable costs (ie costs that are not fixed costs, which only vary with changes in capacity) currently recovered through the interconnection charge are Transpower's high voltage alternating current (HVAC) maintenance costs, operating costs and overhead not recovered through connection charges or customer investment contracts (CICs). Note the Authority recognises that overhead costs are only partially variable.

11.29 To identify the magnitude of these charges, the Authority notes that under Transpower's expenditure proposal for the Commerce Commission’s second regulatory control period (RCP2),[155] Transpower's planned operating expenditure (opex) is roughly $300M per year. Of this expenditure, roughly $60M per year is recovered through the connection and HVDC charges. Annual load in the scenario modelled in this options working paper, gross of major embedded generation, is approximately 42,000 GWh per year. Therefore, the non-connection non-HVDC opex of $240M per year equates to a charge of $5.7/MWh in fully variabilised terms. This would serve as a floor on the interconnection charges paid by load parties.

Modelling results for Application B

11.30 Figure 16 compares the breakdown of total TPM revenue between Applications A and B.

11.31 The deeper connection charge is modelled as recovering:

(a) $300M per year under Application A, but

(b) $20M per year under Application B.

11.32 The modelling probably understates the amount of money to be recovered through the deeper connection charge under Application B by at least $5M per year, as the details of some of the investments that might take place between 2017 and 2019 are not yet known with certainty.

11.33 Nevertheless, relatively little revenue is initially recovered through the deeper connection charge under Application B, as few sizeable investments are anticipated to meet the criteria of being commissioned after the introduction of the new TPM Guidelines, but before 2019. The amount of revenue recovered through the deeper connection charge would increase after 2019 as new assets were commissioned.

11.34 The AoB charge (combined with the SPD charge, under the ‘Base Option + SPD’) is modelled as recovering:

(a) $145M per year under Application A, but

(b) $10M per year under Application B.

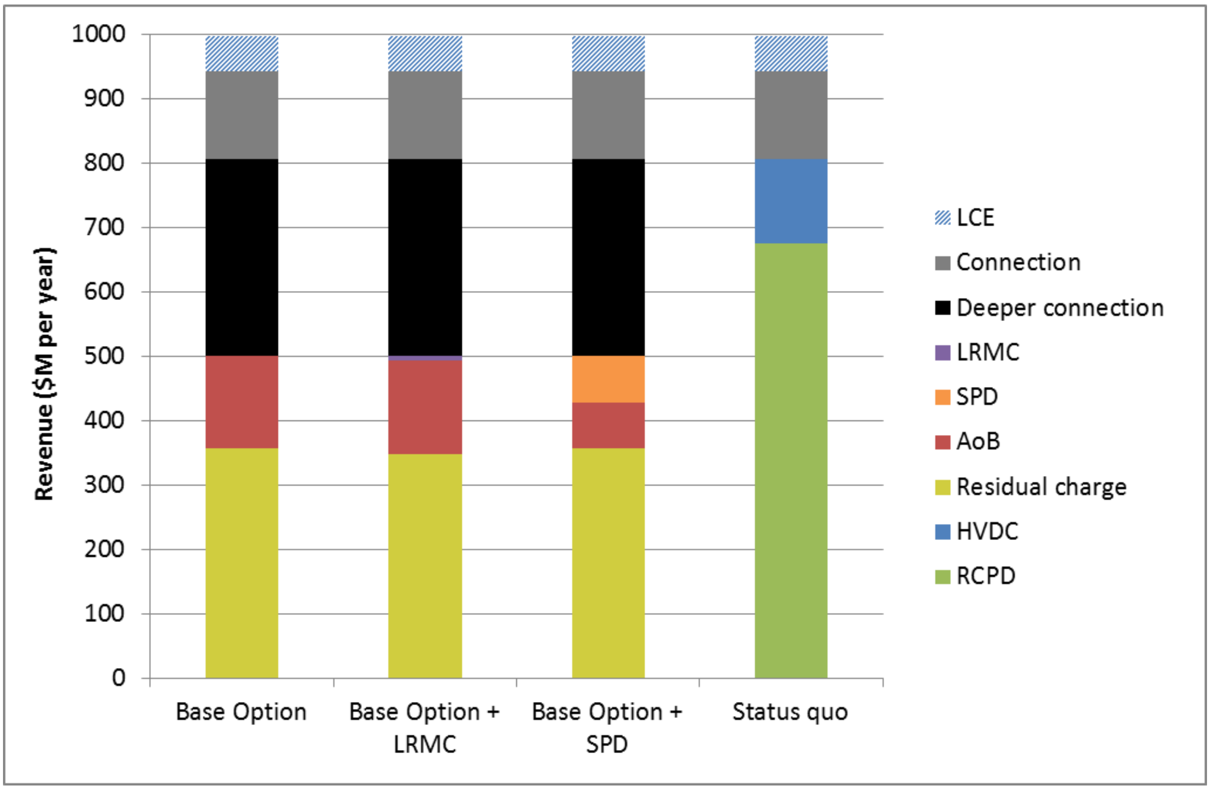
11.35 Again, relatively little revenue is initially recovered through these beneficiaries-pay charges under Application B. The amount of revenue recovered through beneficiaries-pay charges would increase after 2019, as new investments were completed.

11.36 Revenue recovered through the LRMC charge and connection charges is the same as under Application A. This would also be the case for the kvar charge but it has not been modelled.

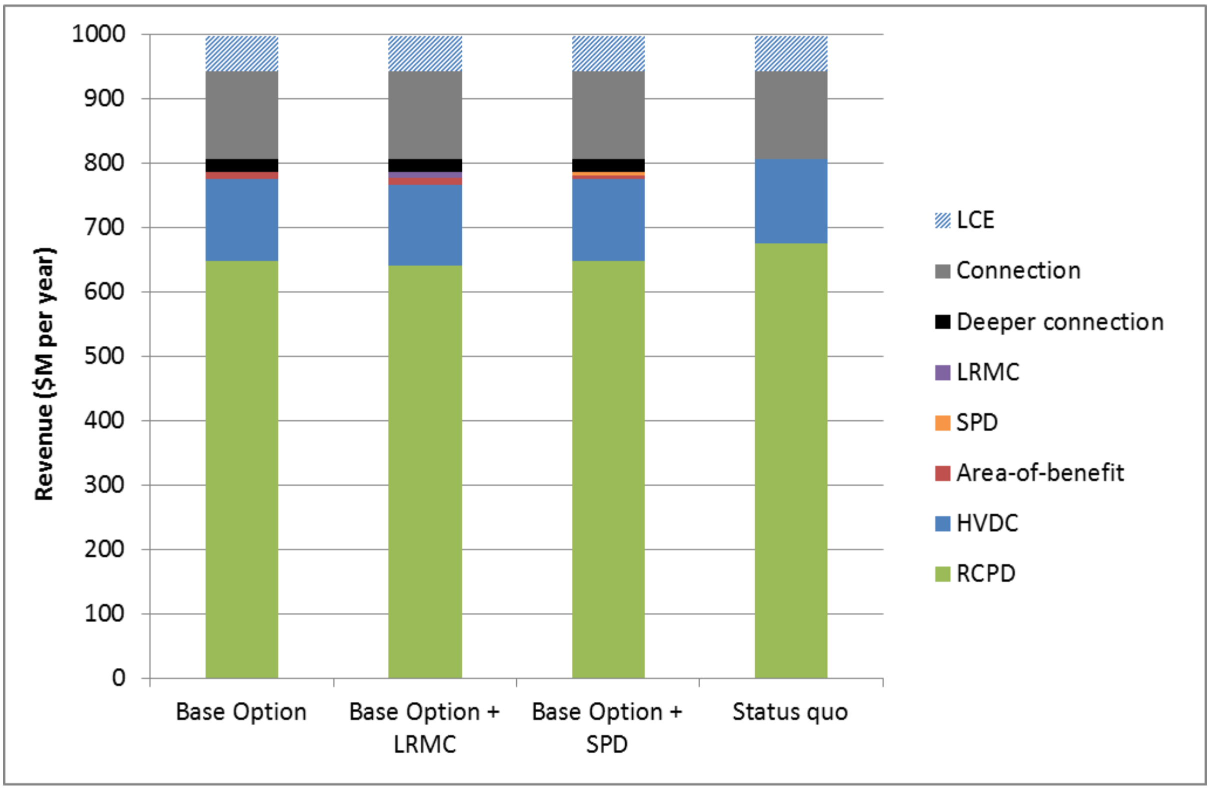
155 Available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf.

Figure 16 - Comparison between Applications A and B of the breakdown of TPM revenue by charge

Application A



Application B



11.37 Figure 17 compares the breakdown of charges across groups of participants between Applications A and B.

11.38 In Application B, the breakdown of charges is similar to the status quo breakdown, for all three options.

11.39 In the modelling, parties that would be better off under Application A relative to the status quo and Application B include:

(a) most major industrial consumers (who would no longer need to pay RCPD charges, and would instead pay a much lower capacity-based charge)

(b) Meridian (who would no longer pay the status quo HVDC charge)

(c) Mass-market customers of some distributors, such as Orion, who have benefited from relatively little major transmission investment in recent years.

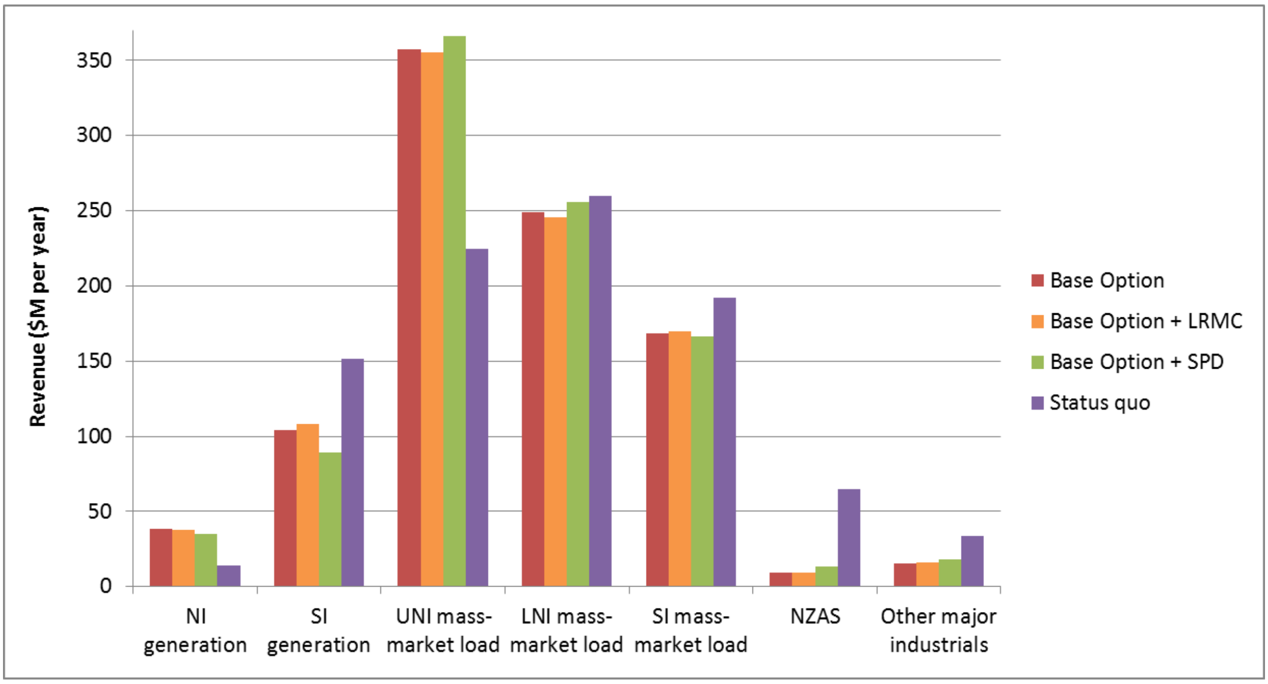
11.40 Parties that would be better off under Application B compared with Application A include:

(a) North Island generators (who would pay less deeper connection and beneficiaries-pay charges under Application B than under Application A), although North Island generators would still be worse off than under the status quo where they do not face either interconnection or HVDC charges

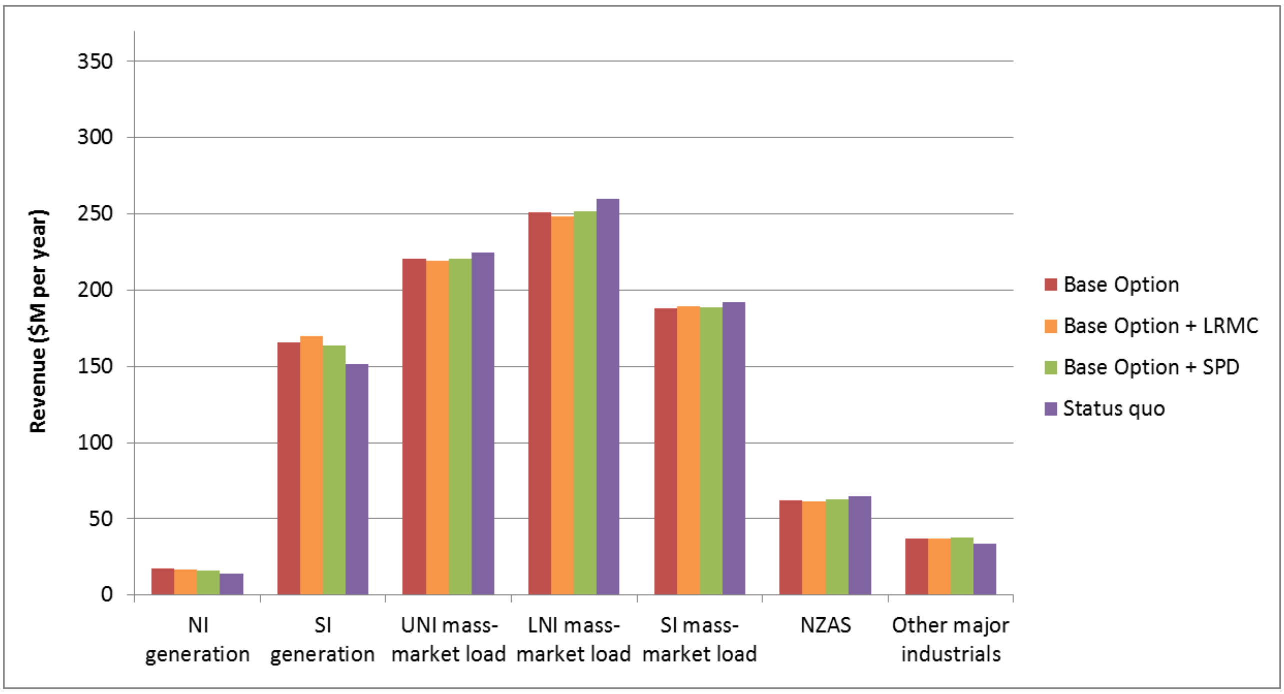
(b) mass-market customers of some distributors, such as Vector, Westpower, Top Energy and Northpower, who have benefited from transmission investments in recent years.

Figure 17 - Comparison between Applications A and B of the breakdown of TPM revenue between groups of parties

Application A



Application B



12 Potential transition alternatives

12.1 If the Authority were to decide to implement any of the options contained in this working paper, or alternative changes, it would also have to decide whether a transition mechanism should be adopted.

12.2 Each of the proposed options in this working paper could lead to potentially large changes in transmission charges under Application A.

12.3 Under Application A, a transition mechanism or price increase cap could be introduced to help manage the potential increases in transmission charges.

12.4 If the Authority were to introduce one of its three options through Application B, the Authority considers that a transition is not required because transmission charges would not be expected to differ greatly from the current TPM charges in the initial years following changes to the TPM.

12.5 In considering options for a transition, the preferred option should best address the problems with the TPM and best achieve the Authority's objectives for the TPM of promoting efficient investment and operation.

12.6 There are three main approaches for applying a transition mechanism or a cap on price increases:

(a) capping the rate of the charge that a customer would face in relation to historical assets/investments

(b) phasing in the new charges over a defined period

(c) a combination of (a) and (b).

12.7 By way of example, the Commerce Commission applied a cap on the rate of change to electricity distribution prices of CPI+10% to minimise the impact of price increases to consumers in both of the last price resets. (An equivalent cap was unnecessary for gas pipelines because all the increases were below CPI+10% anyway.[156])

12.8 The Authority is considering the following potential transition mechanisms and price increase caps:

(i) Alternative 1: cap EDB charging rates (in per-MWh terms) at the upper quartile of all pre-capping EDB charging rates, that is, about $22/MWh. The cap is funded from EDBs whose charging rates are less than the upper quartile

(ii) Alternative 2: cap the increase in transmission charging rates at $12.5/MWh per year, that is, approximately 5 percent of a typical domestic retail tariff, in fully variabilised terms. The transition is funded from EDBs whose charging rates increase at less than $12.5/MWh per year

(iii) Alternative 3: cap the annual increase in transmission charging rates at 20 percent of the current transmission charge (compounded annually) for load

[156] Commerce Commission, Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services, 28 February 2013, paragraph 3.13.

customers. The cap is funded from load customers whose rates are less than under the status quo.

(iv) Alternative 4: phase in over five years the deeper connection, AoB and SPD charges on pre-2017 assets, for load customers. The existing interconnection and HVDC charges are phased out over five years.

12.9 The Authority's alternatives were selected to provide a broad set of transition and capping options to show the range of possibilities for the benefit of consultation.

12.10 Note that there is not intended to be any transition or price cap on connection charges.

12.11 The costs of transition would be recovered, largely or wholly, from EDBs under Alternatives 1 and 2 or load under Alternative 3. As a result, most consumers who would benefit from reductions in transmission charges under the Authority's TPM proposals would receive the reductions at a slower rate; that is, they would pay higher transmission charges than if there was no transition.

12.12 A traditional approach would be to phase in from the existing charges to the new charges over time. This is the approach under Alternative 4. The Authority considers it may be preferable to fund the transition through the capacity-based residual charge as this charge is more efficient than existing charges. However, the Authority has applied several different funding options in modelling the four alternatives above.

Evaluation of transition and capping alternatives

12.13 The transition and capping alternatives being considered may limit the immediate efficiency benefits of applying more efficient charges to existing assets, as depending on the alternative the increases/decreases in charges are limited or they are transitioned in over a period of time. However, this needs to be balanced against the efficiency benefits of limiting the adverse effects of price increases. In particular, limiting these effects may improve the durability of making the change and minimise inefficient behaviour to avoid the impacts of changes to transmission charges. The key effects of the transition alternatives are as follows:

(a) Alternative 1 provides a permanent cap on transmission charges to EDBs, rather than graduated phase in of price increases. This option does not limit price increases to non-EDBs.[157]

(b) Alternative 2 involves a swift transition, in that it allows most of the increases to occur over a 2-year period. Alternative 2 does not avoid large price increases but does preserve the static and dynamic efficiency benefits from Application A.

(c) Alternative 3 provides for a swift transition for most, but not all, customers because it allows a 20 percent increase to transmission charges per year for load customers.[158,159]

157 The Authority notes that this alternative would likely need to apply for a limited time period, such as three years; otherwise some EDBs would never fully transition.

(d) Alternative 4 involves a gradual transition because changes to deeper connection, AoB and SPD charges for existing assets are transitioned in over a relatively long period (five years). Further, under this option the existing charges also apply over a five-year phase out. This option would involve the greatest delay in the efficiency benefits from Application A.

12.14 Capping rates for the two parties that would otherwise experience retail price increases of around 10% (Top Energy and Westpower) would involve minimal funding via the residual because of the relatively small populations and low levels of consumption served by these EDBs.

12.15 The Authority would welcome submitters' views on whether there should be a transition and, if so, what this should be. The Authority has not formed a view about whether a transition mechanism should be adopted or, if so, which transition mechanism should be preferred.

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[158] Northpower and Westpower are the exceptions. Based on the status quo and proposed option prices, ceteris paribus, it would take 6 years for Northpower to transition to the new charges, and 8 years for Westpower.

[159] An anomalous situation may arise where charges are presently zero, which would need to be addressed if Alternative 3 was adopted.

13 Authority's current views on ACOT payments

13.1 The Authority has determined that the Pricing Principles for Distributed Generation in Schedule 6.4 should be reviewed.

13.2 The Authority has included the "Review of Part 6 pricing principles" (ACOT review) in its work programme as an active project, separate from the TPM and distribution pricing methodology reviews. The Authority currently expects that it will commence the review in the 2015/16 financial year.

13.3 Although ACOT payments are not part of the TPM, the Authority has provided its views on the basis that changes to the TPM may affect ACOT payments.

13.4 In brief, the Authority's views developed following the Authority preparing the TPM working paper: *Avoided cost of transmission (ACOT) payments for distributed generation*, and analysing submissions on that paper. The working paper was prepared to help the Authority understand the efficiency implications of any changes to the TPM in relation to ACOT payments.

13.5 A concern the Authority has is that the ACOT payments compensate distributed generators for avoided transmission charges rather than the actual avoided economic costs. This can result in consumers paying transmission charges plus ACOT payments, thus incurring higher overall charges. This would result in higher overall costs than in the absence of distributed generation (DG) in situations where there is no transmission investment to avoid.

13.6 Any changes to the TPM have the potential to change the pricing signals and would affect ACOT payments. In particular, since most of the charges under the options considered in this paper are proposed to be calculated on a capacity rather than peak basis, and since ACOT payments to distributed generators are sometimes made on an avoided charges basis, ACOT payments would fall significantly. The exception to this would be if an LRMC charge were introduced, which is proposed to be calculated on a peak congestion basis.

13.7 Introducing more cost-reflective pricing options would, however, tighten the link between avoided transmission charges and the actual avoided economic costs from DG. A TPM with locational features would likely have some benefits for generators that are situated close to load.

13.8 If a more cost-reflective or dynamically efficient TPM were introduced, the Authority's concerns about the difference between avoided transmission charges and actual avoided economic costs should be reduced.

13.9 The Authority considers that, communicating its intention to conduct the ACOT review, will further inform prospective investors that the current ACOT payment arrangements may be amended. The Authority is exploring potential options for more tightly linking ACOT payments with actual reductions in the economic costs of transmission and distribution.

14 Concluding remarks

14.1 The Authority considers that there has been a material change in circumstances. In particular, the impact of approving $2.8 billion worth of major transmission investment since 2004 is a material change in circumstances, and sufficient to warrant a review of the TPM.

14.2 In addition, advances in technology and the reducing costs of computational power mean more sophisticated TPM options are now available. There have also been significant changes to the regulatory framework that could affect transmission pricing.

14.3 Each of the above, separately or together, constitutes a material change in circumstances. If submitters disagree the Authority would welcome reasons why none of these three matters is a material change in circumstances, and what would represent a material change.

14.4 The options working paper details a preliminary update of the Authority's views on the problems with the current TPM.

14.5 Many of the problems with the TPM reflect that it has not adapted to the impact of substantial investment that has occurred over the last decade. This investment has resulted in substantial increases in transmission charges but, in some cases, the charges do not reflect a change in the transmission service provided to customers.

14.6 The current TPM is therefore increasingly failing to be cost-reflective. It is not clear how the imbalance between charges under the current TPM and the cost of providing transmission services would be for the long-term benefit of consumers.

14.7 The Authority considers there is an important link between transmission pricing and transmission investment approval. That link needs to be considered in determining efficient transmission charges. The Authority considers that durability is also an important consideration in the design of an efficient TPM.

14.8 The Authority would welcome further comments on the problems with the current TPM.

14.9 This working paper details several potential charges that would require reform of the TPM, consisting of a deeper connection charge (involving flow-tracing), a kvar charge, an AoB charge, an LRMC charge, an SPD charge (substantially different from the original SPD proposal) and a residual charge that seeks to avoid inefficiently affecting operational decisions.

14.10 The Authority would welcome comments on each of these potential charges.

14.11 The working paper details three potential options for how the potential charges could be combined (a Base Option, the Base Option + LRMC and the Base Option + SPD).

14.12 The Authority considers that there is potential for these options to better promote the Authority's statutory objective, contained in section 15 of the Electricity Industry Act 2010, of promoting competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.

14.13 Specifically, the Authority considers that the options would result in a more dynamically efficient TPM, and could better promote efficient investment, ensuring lowest cost development of transmission and other electricity assets over time. These dynamic efficiency gains will benefit electricity consumers in the long-term.

14.14 The Authority would welcome comments on the three proposed options, including whether alternative combinations should be considered, or other options not proposed in the options working paper.

14.15 The Authority is also further considering the impact of the potential TPM changes on electricity prices paid by residential consumers. Some submitters have suggested that any new dynamic pricing charges apply only to new assets and investments. This would have the advantage of avoiding substantial changes in the allocation of transmission costs, but would mean forgoing some potential efficiency gains. This would also require two charging regimes to be operated simultaneously. An alternative would be to adopt a phased introduction of any new charges. The Authority would welcome submitter views on these alternatives.

Appendix A Modelling scenario and simplifying assumptions made for modelling purposes

A.1 For the convenience of readers, this Appendix predominantly repeats the content of Appendix A in the options working paper.

The scenario

A.2 All three options and the status quo are applied to a hypothetical future scenario. The scenario covers a 3-year period, which is intended to represent the 2017, 2018 and 2019 calendar years.

A.3 The scenario assumes demand growth of 5% between 2011 and 2017 (slightly under 1% per year), and more rapid demand growth between 2017 and 2019.

A.4 These assumptions represent faster demand growth than has been observed in recent years. The Authority plans to repeat the analysis for lower and higher demand growth sensitivities and publish the results on its website during the consultation period.

A.5 The scenario assumes that two coal-fired Huntly units are available, and that no other thermal generation plants will retire before the end of 2019.

A.6 The scenario assumes that a new 50 MW geothermal plant will be commissioned near Wairakei at the start of 2019 (in order to meet demand growth). No other new generation investment is modelled.

A.7 Mighty River Power has recently announced it will decommission Southdown[160] and increase capacity at Whakamaru.[161] Further, Meridian has announced it will increase capacity at Waitaki.[162] These changes are not included in the scenario, because the Authority did not become aware of them until after modelling work had begun. The Authority will revisit this as part of the modelling work for the second issues paper.

A.8 The scenario assumes that the following transmission investments will be completed by 2017:[163]

(a) Lower South Island (LSI) Reliability

(b) LSI Renewables

(c) BPE-HAY reconductoring.

A.9 The Authority appreciates that, in reality, some of these three investments may not be fully commissioned by 2017.

A.10 In addition, the scenario assumes that the following transmission investments will be completed between 2017 and 2019:

(a) PAK-WKM series compensation[164]

160 Mighty River Power, Media Release, Renewables growth behind closure of Southland thermal station, 24 March 2015.

161 Refer to: NZ Energy and Environment publication, 12 November 2014, Vol 11, No. 30, page 1.

162 Refer to: http://ecogeneration.com.au/news/hydro_powering_on_in_new_zealand/080465/.

163 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

(b) some form of investment reinforcing OTA-WIR[165]

(c) interconnecting transformers at OTA and PEN[166]

(d) OTB-HAY reconductoring.[167]

A.11 In reality, it is uncertain whether or when these four investments will take place, or in what form, as they are still in the planning process.

Implementing the scenario in vSPD

Approach

A.12 The scenario has been implemented using the Authority's vSPD model.[168] Minor modifications have been made to the vSPD code for this purpose, aimed mainly at producing the required outputs.[169]

A.13 The scenario is produced by:

(a) taking real final pricing cases from the 2011, 2012 and 2013 calendar years, in the GDX format used by vSPD

(b) modifying the GDX files as described below[170]

(c) using the (slightly modified) version of vSPD to solve the cases

(d) loading selected vSPD output files into a SQL database.
(The Authority has published a copy of this table, so that participants can reproduce the calculation of simulated charges without needing to rerun vSPD.)

A.14 The 2017 year of the scenario is based on modified 2011 final pricing cases, the 2018 year on modified 2012 cases, and the 2019 year on modified 2013 cases.

Demand assumptions

A.15 Demand at all nodes except Tiwai and Kawerau is scaled up by:

(a) 5% in 2017 (compared to 2011)

(b) 7% in 2018 (compared to 2012)

(c) 9% in 2019 (compared to 2013).

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164 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

165 Refer Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf.

166 Refer Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf.

167 Refer integrated transmission plan at: https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates.

168 http://www.emi.ea.govt.nz/Tools/vSPD

169 The Authority became aware, just before publication of this paper, that the modifications to vSPD carried out for the purpose of this analysis introduced an error, which lay in the calculation of market benefits to IR providers. The error does not affect any of the results shown in this paper.

170 For the convenience of submitters, the Authority is considering preparing an alternative version of the analysis that does not use modified GDX files. Instead, it would use the main (trunk) version of vSPD and unmodified GDX files, and employ overrides to produce the desired scenario. If the Authority does this, it will publish the files on its website during the consultation period.

A.16 Demand at Tiwai is unmodified. Demand at KAW0112 and KAW0113 is scaled down by roughly 40%.

A.17 Demand-side bids are modelled at the following nodes: KAW0112, KAW0113, KIN0111, KIN0112, KIN0113, WHI0111. These bids are based on actual bids into the spot market price-responsive schedule (PRS). Bid quantities at Kawerau are, again, scaled down by roughly 40%.

A.18 The Authority appreciates that, in practice, some of these parties might not place dispatchable demand bids. However, modelling these demand-side bids in the scenario helps to represent the price sensitivity of the relevant loads.

A.19 The Authority became aware, just before publication of this paper, that there were errors in the way it had constructed synthetic demand-side bids at Kawerau and Kinleith. Only about 1% of trading periods were affected. The Authority has tested the effect of this error on prices and quantities in the scenario and concludes that it is not material.

Generation assumptions

A.20 Synthetic offers are used for the two remaining coal-fired units at Huntly – with roughly half the capacity being offered at $0/MWh, and the remainder offered at up to $100/MWh.

A.21 The new 50 MW geothermal generator is modelled as baseload.

A.22 The following plants, which were commissioned after the beginning of 2011, are modelled as being in place throughout the entire 3-year period:

(a) Te Mihi and Ngatamariki geothermal (modelled as baseload)

(b) Mill Creek wind (output assumed to be proportional to West Wind)

(c) McKee peaker (actual offers used where available, otherwise offers from Stratford 2 used where available, otherwise 100 MW offered at $150/MWh).

A.23 No attempt is made to track simulated hydro storage or to consider how this might result in changes to generation offers (relative to the actual offers made in 2011-13).

A.24 No attempt is made to consider how the various transmission charging options might affect participant behaviour.

Transmission network assumptions

A.25 All days in the scenario use the network configuration from 31 July 2013, modified to include the NAaN upgrade, Wairakei Ring, LSI Reliability, LSI Renewables and BPE-HAY reconductoring.

A.26 Shoulder and summer line ratings are modelled as being 95% and 90% of the winter line rating, respectively.

A.27 Where a node does not exist in the 31 July 2013 network configuration, its demand is shifted to a node that does exist:

(a) load at DAR0111 and MPE0331 is moved to MPE1101

(b) load at KOE0331 and KTA0331 moved to KOE1101

(c) load at KKA0331 is moved to CUL0661

(d) load at OKI0111 is moved to OKI2201

(e) load at PAP is moved to ISL0661.

A.28 Instantaneous reserve requirements are adjusted to reflect the availability of the bipole HVDC throughout the three-year period. In particular:

(a) DCCE i_HVDCPoleRampUp is set to 700

(b) DCCE i_FreeReserve is set to the maximum of DCCE i_FreeReserve and GENRISK i_FreeReserve

(c) i_TradePeriodBranchCapacity is set to approximately 700 for the HVDC poles

(d) additional types of risk parameter associated with Pole 3 commissioning are removed.

A.29 Group and branch constraints are turned off in the vSPD modelling:[171]

(a) in order to avoid the difficulty of determining the constraint parameters that will apply in 2017-19

(b) to reflect that most constraints that might bind would either be managed operationally or resolved through investment

(c) on the assumption that the results of interest (simulated transmission charges) are not sensitive to the inclusion of group and branch constraints.[172]

A.30 Investments assumed to be commissioned between 2017 and 2019 (that is, PAK-WKM series compensation, OTA-WIR reinforcement, ICTs at OTA and PEN and OTB-HAY reconductoring) are not modelled in vSPD – in large part, because it is not clear what form these investments will take. However, these investments are taken into account when modelling transmission charges.

A.31 For the purpose of modelling transmission charges, Cobb is treated as being an embedded generator.

Revenue to be recovered

A.32 It is assumed Transpower's non-connection revenue requirement will be approximately $1,000M per year (excluding static reactive support costs). This is broadly consistent with Transpower's forecast revenue.[173] The revenue requirement assumes no change in revenue as a result of Transpower's individual price path.

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171 However, selected group constraints are used when carrying out the counterfactual cases for the SPD charge – in order to model the effect of removing the investment in question.

172 The Authority has carried out an experiment to test whether this assumption is valid for the SPD charge, and concludes that the SPD charge is not sensitive to the inclusion of constraints (other than the group constrains used in the counterfactual case to model the effects of removing the investment, which are essential). The Authority is also carrying out an experiment to test whether this assumption is valid for the deeper connection charge, and plans to publish the results during the consultation period.

173 Refer: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/RCP2%20revenue%20-%20revised%20forecast%20%28July%202014%29.pdf.

A.33 Some charges are based on the revenue requirements associated with specific investments. The assumed revenue requirements, based on indicative information supplied by Transpower, are set out in Table 11.

Table 11: Assumed revenue requirements for specific investments

Investment	Assumed revenue requirement ($M per year)	Reference
NIGU	91	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/north-island-grid-investment-proposal/
HVDC Pole 3	80	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/hvdc-grid-upgrade/
HVDC Pole 2	55	N/A
NaaN	34	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/north-auckland-and-northland-proposal-history/
LSI Renewables	27	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-renewables/
Wairakei Ring	13	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2008-gup/wairakei-ring-economic-investment-history/
Otahuhu GIS	11	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2005-gup/otahuhu-substation-diversity-proposal-history/

Investment	Assumed revenue requirement ($M per year)	Reference
BPE-HAY reconductoring	8	http://www.comcom.govt.nz/regulated-industries/electricity/electricity-transmission/transpower-major-capital-proposal/bunnythorpe-haywards-a-and-b-lines-conductor-replacement-investment-proposal/
UNI dynamic reactive support	8	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/upper-north-island-dynamic-reactive-support-investment-proposal-archive/
USI reactive support (IGE 4)	5	https://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/grid-development-proposals-archive/ige-applications/upper-south-island-reactive-support-history/
LSI Reliability	3	http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2009-gup/lsi-reliability/
PAK-WKM series compensation	7	Integrated transmission plan at https://www.transpower.co.nz/about-us/industry-information/rcp2-submission-and-itp/rcp2-regulatory-templates
OTB-HAY reconductoring	3	
Some form of investment reinforcing OTA-WIR	3	Section 6.4.2 of Transpower's RCP2 proposal at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/main-proposal-rcp2.pdf
ICTs at OTA and PEN	3	

(Note: It is unclear whether or when the last four investments listed will take place, or in what form, as they are still in the planning process.)

A.34 Together, these investments total a revenue requirement of about $350M per year.

A.35 The assumed revenue requirement is expressed, and all charges are calculated, on a '$M per calendar year' basis – c.f. the '$M per pricing year' basis actually used by Transpower.

A.36 It is assumed that $50M per year of post-FTR non-connection LCE will be available as a credit against transmission charges.

A.37 In the 'status quo' scenario, the calculation of LCE rebates is affected by the breakdown of non-connection post-FTR LCE between HVDC LCE and non-HVDC LCE. For this purpose, it is assumed that HVDC post-FTR LCE is $5M per year and non-HVDC post-FTR LCE is $45M per year.

Simplifying assumptions applied in the calculation of transmission charges

A.38 The following list is not exhaustive but covers the main simplifying assumptions.

A.39 The subsections relating to specific charges are not intended to be stand-alone – they should be read alongside the descriptions of the corresponding charges in the main text.

Deeper connection charge

A.40 Existing connection assets, and the HVDC link, are not eligible to become deeper connection assets.

A.41 The classification of assets modelled in SPD as connection or interconnection, and the calculation of the Regulatory Asset Base (RAB) value associated with each SPD asset, are both somewhat approximate. In practice, Transpower would be able to perform these calculations more accurately.

A.42 The revenue requirement associated with each asset (including depreciation, Transpower's recovery of its capex costs, and O&M attributed to the asset) is assumed to be 15 percent of the RAB value. This is an approximation. In practice, the ratio of revenue requirement to asset value would vary between assets.

A.43 The following provides details on the HHI calculation for identifying deeper connection assets:

(a) The methodology utilises a power flow tracing algorithm developed by the Authority that is able to accurately determine the main users of interconnection assets. It allocates the flow across each asset in each trading period between load or generation users of the asset. These flow shares are then averaged across trading periods.

(b) The output of the vSPD analysis, used to prepare the scenario, is an input to the flow tracing analysis.

(c) The load HHI calculation is based on the averaged flow shares of load parties; the generation HHI calculation is based on the averaged flow shares of generation parties.

(d) An asset is considered to be deeper connection if it has an HHI in excess of 4,000 for either load or generation.

(e) If the HHI is above 5,000 the revenue requirement in relation to the asset is fully recovered through the deeper connection charge.

(f) If the HHI is between 4,000 and 5,000, then the amount to be recovered is derated. A linear derating is applied – for instance, if the load HHI of an asset is 4,500, then deeper connection charges on load for that asset are halved.

A.44 If an asset is identified as deeper connection, then the deeper connection charges associated with the asset are allocated between load nodes (if it has a load HHI in excess of 4,000) and generation nodes (if it has a generation HHI in excess of 4,000) that are deemed to be ‘connected by’ the asset – in proportion to their AMD or AMI respectively.

A.45 A node is deemed to be connected by a particular deeper connection asset if the node’s mean flow share for the asset is at least 3 percent of its AMD (for a load node) or its AMI (for a generation node).

A.46 If there are multiple load parties at a node, then the charge is modelled as being allocated between these load parties in proportion to their share of total electricity consumption at the node. (In practice, the charge might instead be allocated in proportion to contribution to AMD.)

A.47 Investments assumed to be commissioned between 2017 and 2019 (that is, PAK-WKM series compensation, OTA-WIR reinforcement and ICTs at OTA and PEN) are not included in the flow tracing – in large part, because it is not clear what form these investments will take. However, these investments are taken into account when modelling deeper connection charges. The allocation of charges for these investments is carried out on an ad hoc basis, based on the Authority's understanding of the parties that would likely be deemed to be 'connected by' the relevant assets.

A.48 The post-FTR LCE occurring across each deeper connection asset is assumed to offset the deeper connection charges for that asset.

A.49 Post-FTR LCE occurring on deeper connection assets is estimated by:

(a) determining the rentals produced by each asset in the vSPD scenario

(b) scaling all rentals so they sum to $165 million over 3 years ($55 million per year).

LRMC charge

A.50 The LRMC charge applies to both load and generation parties. A LRMC is calculated, and charges are applied, to signal the cost for each potential future investment that is eligible.

A.51 The LRMC charge is not applied to connection investments, or investments that would largely or wholly consist of deeper connection assets.

A.52 LRMC is calculated using the MIC (marginal incremental cost) method.

A.53 For convenience, it is assumed LRMC is not recalculated during the 2017-19 period. The same LRMCs are used for all three years.

A.54 The total LRMC charge payable in 2017, 2018 and 2019 should be calculated by comparing coincident peak congestion in 2019 and 2016 *(since the charge for 2017 is based on changes in coincident peak congestion between 2016 and 2017, the charge for 2018 is based on changes between 2017 and 2018, and the charge for 2019 is based on changes between 2018 and 2019 – with the total of these three increments equalling the change between 2016 and 2019)*. In order to apply a comparison between 2016 and 2019, simulated 2016 outcomes need to be obtained (bearing in mind that the scenario does not include a 2016 year). For generation, these 2016 outcomes have been assumed to be the same as 2017 outcomes. For load, these 2016 outcomes have been derived by taking simulated 2018 outcomes and decreasing demand by 3 percent.[174]

A.55 As set out in paragraph 7.13, SRMC should be subtracted from LRMC before calculating the LRMC charge. However, the subtraction of SRMC from LRMC is omitted in this working paper on the grounds that the effect would be relatively immaterial. Calculated LRMCs are in the tens of dollars per kW, while SRMCs (that is, price differences across the relevant constraint in the period of annual peak congestion) may be as low as tens of dollars per MWh – three orders of magnitude smaller than LRMC.

Area-of-benefit charge

A.56 The AoB charge can apply to either load or generation parties or both, depending on the nature of the investment concerned. Charges are applied for each investment that is eligible.

A.57 Embedded generation is potentially subject to the charge if it is part of a scheme over 10 MW.

A.58 The AoB charge is not applied to investments that largely or wholly consist of deeper connection assets.

A.59 The Authority has modelled the AoB charge as follows:

(a) charges on load are allocated in proportion to:

(i) AMD, for major industrial customers

(ii) deemed capacity, for EDBs – calculated as the sum of the nominal capacities of the active ICPs in their network area. The nominal capacity depends on the ICP's metering category code, as set out in Table 12. The Authority acknowledges there is substantial room to refine these numbers

(b) charges on generation are allocated by MWh.

A.60 For the purpose of modelling numbers of ICPs in each network area, the Authority has assumed that the percentage breakdown of active ICPs across categories, nodes, networks and retailers will not change.

174 Another option would have been to take simulated 2017 outcomes and decrease demand by, say, 1%, but this option was considered less suitable because 2017 peak demand outcomes are very atypical, being based on 2011.

Table 12: Nominal capacities used for mass-market consumers under the area-of-benefit and residual charges

Meter category code[175]	Nominal capacity (kW)
Unmetered	20
1	20
2	100
3	700
4	1,750
5	2,500

A.61 For instance, the deemed capacity for Aurora Energy is modelled as (approximately) 2,070 MW, calculated as the sum of (approximately):

(a) 500 unmetered ICPs @ 20 kW

(b) 87,000 category 1 ICPs @ 20 kW

(c) 1,000 category 2 ICPs @ 100 kW

(d) 150 category 3 ICPs @ 700 kW

(e) 40 category 4 ICPs @ 1,750 kW

(f) 20 category 5 ICPs @ 2,500 kW.

A.62 This deemed capacity substantially exceeds Aurora Energy's maximum load. The same is true for other distributors.

SPD-based charge

A.63 The SPD charge can apply to either load or generation parties or both. Charges are applied for each investment that is eligible.

A.64 Embedded generation faces the SPD charge:[176]

(a) if it is modelled as a generator in SPD, or

(b) if it is part of a scheme over 10 MW, and there is net injection at its node.

A.65 The investments included in the calculation of SPD charges in the simulated scenario are:

(a) HVDC Pole 3

175 Each metered ICP is assigned a meter category code, indicating the capacity of the customer connection. These codes are explained at: http://www.ea.govt.nz/dmsdocument/8583. For instance, a 400V non-half-hourly meter with maximum current of 200 kVA would be code 2. Numbers of ICPs by meter category code are published at: http://www.emi.ea.govt.nz/Reports/VisualChart?reportName=AWNGPD&categoryName=Retail&reportGroupIndex=9&reportDisplayContext=Gallery#reportName=AWNGPD.

176 This approach to embedded generation is proposed to ensure that the charge is designed so that it does not promote inefficient behaviour by parties seeking to avoid charges. Refer to the beneficiaries-pay working paper, paragraphs 7.91 to 7.102.

(b) HVDC Pole 2

(c) Wairakei Ring *(though half the costs of this investment are modelled as being recovered through the deeper connection charge)*

(d) BPE-HAY reconductoring

(e) OTB-HAY reconductoring.

A.66 The SPD counterfactuals used are broadly the same as in the beneficiaries-pay working paper.[177] Key group constraints are modelled in the SPD counterfactuals.

A.67 For instance, in the Wairakei Ring counterfactual:

(a) the following branches are removed: WKM_PPI_WRK1.1, WKM_PPI_WRK2.1, WKM_PPI_WRK1.2, WKM_PPI_WRK2.2

(b) the following branches, which were marked as open in the base case, are closed: THI_WKM1.1 and THI_WRK1.1

(c) the following branch constraint is added: -1.26*ATI_OHK.1 + 0.84*THI_WKM1.1 < 500.

A.68 In the OTB-HAY reconductoring counterfactual, the HVDC link is unavailable.

A.69 The value of VoLL used in the SPD method is:

(a) $3,000/MWh, for most investments

(b) $1,000/MWh, for HVDC Pole 2 and OTB-HAY.[178]

A.70 The Authority anticipates that, in practice, dispatchable demand bids would be included when applying the SPD method.[179] In this modelling exercise, dispatchable demand bid information was not available. Therefore, synthetic bids were modelled, as discussed earlier in this Appendix.

A.71 Benefits or dis-benefits are calculated at the nodal level, with three exceptions. SPD charges have been calculated at the substation level for Glenbrook (GLN), Kawerau (KAW), and Kinleith (KIN).[180] For simplicity:

(a) all SPD charges for the GLN substation would be paid by NZ Steel –in practice some would be paid by Counties Power

(b) all SPD charges for the KAW substation, except KAW0111, would be paid by Norske Skog – in practice the other parties at the site would also be affected

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177 Available at http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c7492.

178 The Authority considers that this ensures that the benefit calculation reflects the benefits in the long-run from the investment. Refer to the beneficiaries-pay working paper, Table 3, page 20. Also paragraphs 7.71 to 7.79.

179 Incorporation of demand response into the SPD method can have a significant impact on the estimated benefit to price responsive load from transmission investment. Given that dispatchable demand is in place, the Authority's view is that dispatchable demand bids should be used to calculate the SPD charge if it is part of any changes to the TPM. Refer to the beneficiaries-pay working paper, paragraph 7.69.

180 Calculating benefits, and therefore the SPD charge, across multiple nodes at these locations is appropriate given they are effectively the same location.

(c) all SPD charges for the KIN substation, except KIN0331, would be paid by CHH.

A.72 Dis-benefits can be netted against benefits at the nodal level, within 3 years, but not over a wider spatial scale or a longer time period. If there is a net dis-benefit at a given node in a given year, then the SPD charge is zero rather than a negative number.

A.73 Netting is applied after capping, which is applied after pooling (dis)benefits at each of the three substations listed above.

A.74 The Authority anticipates that, in practice, both the (dis)benefits adhering to IR providers, and the off-market (dis)benefits adhering to IR availability cost payers, would be included when applying the SPD method. However, to date this has not been modelled. Rather, the modelling has only included the market (dis)benefits adhering to IR providers, for load parties that provide IR, for Pole 2 and 3 (which are the two investments that could be expected to have the most effect on IR prices and quantities).

Mass-market load capacity charges (residual charge)

A.75 The Authority has modelled the residual charge as being allocated in proportion to:

(a) AMD, for major industrial customers

(b) deemed capacity, for EDBs – calculated as the sum of the nominal capacities of the active ICPs in their network area. The nominal capacity depends on the ICP's metering category code, as set out in Table 12.

HVDC charges – status quo

A.76 The calculation of HVDC charges in this work is approximate and includes several simplifying assumptions. Parties should not rely on it to form conclusions about the HVDC charges they will pay. They should contact Transpower if they have any questions about the HVDC charge.

A.77 The Authority assumes that, for the purpose of calculating the status quo HVDC charge, Benmore's injection is capped at 465 MW and Clyde's injection is capped at 395 MW.

A.78 The Authority is generally clear as to how to calculate HVDC charges, but is unclear how exactly Transpower adjusts HAMI quantities for Waipori and for the various generators on the West Coast of the South Island, and has made some simplifying assumptions in this regard.

A.79 As for all other options, HVDC charges have been calculated with regard to calendar years rather than pricing years or measurement years.

RCPD charges – status quo

A.80 The calculation of RCPD charges in this work is approximate and includes several simplifying assumptions. Parties should not rely on it to form conclusions about the RCPD charges they will pay. They should contact Transpower if they have any questions about the RCPD charge.

A.81 The Authority is generally clear as to how to calculate RCPD charges, but is unclear how exactly to calculate RCPD charges for offtake at grid-connected generation nodes, and has made some simplifying assumptions in this regard.

A.82 For convenience, the Authority has assumed that all RCPD charges incurred at Glenbrook are paid by NZ Steel. It would have been more correct to divide these charges between NZ Steel and the other parties at the site.

A.83 As for all other options, RCPD charges have been calculated with regard to calendar years rather than pricing years or measurement years.

Appendix B Treatment of LCE

B.1 The LCE working paper set out the theoretical foundations for use of LCE to fund the costs of transmission.[181] Since LCE arises from the interaction between buyers and sellers in the wholesale electricity market, using LCE to fund the costs of transmission is a market approach and therefore most preferred under the DME framework.

B.2 The Authority analysed submissions on the LCE working paper. Table 13 below summarises the Authority's understanding of submitter preferences for the treatment of LCE and the main reason for each submitter's preferred option.

Table 13: Submitter preferences for the treatment of LCE in the LCE working paper

Option
Status quo: Continue to allocate LCE to transmission customers in proportion to their transmission charges, with the allocation of LCE to HVDC, interconnection and connection customers determined through Transpower's rental guides.[182]
Option 1: Credit LCE against MAR in bulk.[183]
Option 2: Apply LCE originating from connection assets against connection charges for those individual connection assets. Credit remaining LCE against the remainder of the MAR in bulk.[184]
Option 3: Apply LCE originating from connection assets against charges for individual connection assets, credit LCE arising from other asset classes by asset class.[185]
Alternative suggested by some submitters: Credit against wholesale purchases (load) to offset their locational price risk in general.[186]

B.3 Some submitters questioned whether there was a problem with the current allocation of LCE that necessitated a change, or whether a change to netting LCE off transmission charges would be net beneficial. The Authority

[181] See in particular, Electricity Authority, Transmission pricing methodology: Use of LCE to offset transmission charges, 21 January 2014, paragraphs 4.6-4.7.

[182] Based on submissions, this option was supported, partially supported, or supported subject to further analysis by Orion, ENA, Andrew Shelly Economic Consulting, and Powerco.

[183] Based on submissions, this option was supported, partially supported, or supported subject to further analysis by Vector, Genesis, and Transpower.

[184] Based on submissions, this option was supported, partially supported, or supported subject to further analysis by Contact, Meridian, MRP, Genesis, MEUG, and Transpower.

[185] No submitters appeared to support option 3.

[186] This option was supported by Nova and Trustpower.

considers that there are some issues with the current allocation of LCE, including, in some cases, LCE payments not being received by parties ultimately paying transmission charges, and being allocated to some parties participating in the FTR market. However, these problems are not the principal reasons for the Authority considering use of LCE as a credit against transmission charges. Rather, the Authority is required to consider the most efficient means of recovering Transpower's revenue for owning and operating its transmission services and, in theory, LCE is the most appropriate source of revenue.

B.4 Some parties have suggested that LCE not used to fund FTRs should be allocated to purchasers to offset their locational price risk in general. The Authority does not agree. The Authority, and the Electricity Commission before it, examined this option for managing locational price risk and concluded managing locational price with FTRs alone would have greater net benefits. Further, it is still necessary to find a use for the residual LCE revenue that remains after settlement of FTRs (post-FTR LCE) and the Authority considers the best use of this revenue is a credit against transmission charges. Allocating post-FTR LCE to purchasers is not efficient because it can distort nodal price signals.

B.5 Where LCE has been used to fund FTRs, the LCE credited against the charges of consumers that pay transmission charges would be the residual remaining after funding of FTRs, including remaining FTR auction revenue etc.

B.6 Submitters were concerned about LCE volatility. The volatility in net terms should not, in general, differ from the status quo because each customer would still be liable for their full transmission charges but may receive a credit note for LCE. This is the same as under the status quo.

B.7 Further, FTRs should reduce any volatility since, in theory, the price paid for FTRs would reflect FTR participants' expectations about the average price differences between FTR nodes, rather than the actual price differences (which give rise to the LCE). However, this is unlikely to eliminate volatility because FTRs do not cover the whole grid, and because FTRs are monthly, so the value of FTRs will reflect FTR participants' underlying expectations of the value of FTRs in a particular month.

Design details for LCE[187]

B.8 As proposed in the LCE working paper, the Authority is proposing to apply an LCE credit against transmission charges as follows:

(a) LCE attributable to an individual connection asset or deeper connection asset would be credited against the charges of customers that pay for that asset

(b) LCE not attributable to connection or deeper connection assets would be credited in bulk against Transpower's remaining MAR.

[187] In the paragraphs that follow "LCE" should be read as including the surplus funds that remain after settlement of FTRs, as appropriate.

B.9 At present, transmission prices are determined based on a capacity measurement period that is the 12 month period ending 31 August immediately before the commencement of a pricing year. Transpower typically publishes prices for a pricing year in the December preceding the pricing year.

B.10 Part D of the Benchmark Agreement currently requires that Transpower calculate a customer's share of LCE every month in accordance with its "prevailing methodology", and issue the customer a credit note for the customer's share as a deduction from the grid charges payable by the customer.

B.11 The Authority considers it appropriate for LCE to be allocated as it arises, and applied as a credit note under the Benchmark Agreement on a monthly basis, as is currently the case. This should not cause problems for EDBs' compliance with Part 4 of the Commerce Act provided they treat any credit notes for LCE on the same basis as any LCE they currently receive.

B.12 However, the Code would need to be amended to set out a new methodology for allocating LCE to each customer. The Code would also need to deem that the methodology for allocating LCE in the Code is the prevailing methodology under Part D of the Benchmark Agreement.

B.13 An alternative to applying LCE on a monthly basis as a credit note would be to adopt an LCE measurement period that matches the capacity measurement period for transmission charges. This would have the benefit of certainty for payers of transmission charges. However, it would mean that LCE would need to be held by a party (for example, Transpower or the Clearing Manager) for up to 18 months after the LCE arises before being credited to customers. The funds could be held in an interest-bearing account so that LCE payments included interest earned. An approach similar to this was considered when the Authority was designing FTRs but this was not supported by the Location Price Risk Technical Group or submitters. This was because of concerns the opportunity cost of holding the funds was greater than the rate of interest. For this reason, the Authority does not propose this alternative.

<u>LCE arising in relation to connection and deeper connection assets used as credit against the charges for the assets</u>

B.14 LCE that is attributable to an individual connection asset or individual deeper connection asset would be used as a credit against the charges for that asset. For shared assets, each customer that pays for the asset would be allocated LCE in the same proportion as the customer pays for the asset.

B.15 To do this, the Code would need to be amended to include a formula to determine the LCE attributable to each connection asset and each deeper connection asset and (for shared assets) between customers that pay for the asset.

B.16 As stated above, the LCE would be credited against transmission charges by way of credit note, in accordance with the Benchmark Agreement.

<u>Credit remaining LCE against remaining revenue</u>

B.17 Under all options, the LCE that is not attributable to connection assets or deeper connection assets would be credit in bulk against the portion of Transpower's revenue not recovered through connection charges or deeper connection charges.

B.18 To do this, the Code would need to be amended to include a formula to determine how the non-connection/deeper connection LCE would be allocated to each customer that pays non-connection/deeper connection transmission charges.[188]

B.19 As stated above, the LCE allocated to a customer would be credited against the customer's transmission charges by way of credit note, in accordance with the Benchmark Agreement.

B.20 An alternative to the method described above, would be to incorporate the LCE component into the calculation of transmission charges themselves, so that the actual transmission charges calculated by Transpower are net of LCE. For example, clause 8 of the TPM could be amended to include the LCE component.

B.21 Part D of the Benchmark Agreement does not currently provide for LCE to be incorporated into TPM charges. It requires Transpower to allocate LCE and issue a credit note.

B.22 At this stage, the Authority does not think it would be efficient to amend the Benchmark Agreement for the sole purpose of allowing LCE to be incorporated into the calculation of transmission charges, as it would involve considerable time and cost. However, if the Authority were to decide to amend the Benchmark Agreement in relation to other aspects of the TPM proposal, the Authority may reconsider whether to make amendments in relation to LCE.

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188 For example (based on the current TPM):

$$x = (\mathrm{y} - \mathrm{z})\,\frac{a + b}{\frac{1}{12}(R_{IC} + R_{HVDC})}$$

Where

x = LCE to be allocated to a customer in a month, not including LCE arising on connection and deeper connection assets.

y = Total LCE received by Transpower in the relevant month.

z = LCE allocated in relation to connection assets and deeper connection assets for the relevant month.

R_{IC} = The portion of AC revenue to be recovered through interconnection charges.

R_{HVDC} = HVDC revenue.

a = The customer's monthly interconnection charge.

b = The customer's monthly HVDC charge.

Appendix C Choice of capping period used for the SPD-based charge

C.1 Under the SPD method, a key design decision is the choice of capping period.

C.2 With daily capping, the revenue recovered for one day for a given investment cannot exceed (1/365) of the annual revenue requirement of the investment.

C.3 With monthly capping, the revenue recovered for one month for a given investment cannot exceed (1/12) of the annual revenue requirement of the investment.

C.4 With annual capping, the revenue recovered for 1 year for a given investment cannot exceed the annual revenue requirement of the investment.

C.5 If there was no cap the revenue from the SPD charge could potentially exceed the cost of the asset (which would reduce the amount of revenue needed to be recovered through the residual charge).

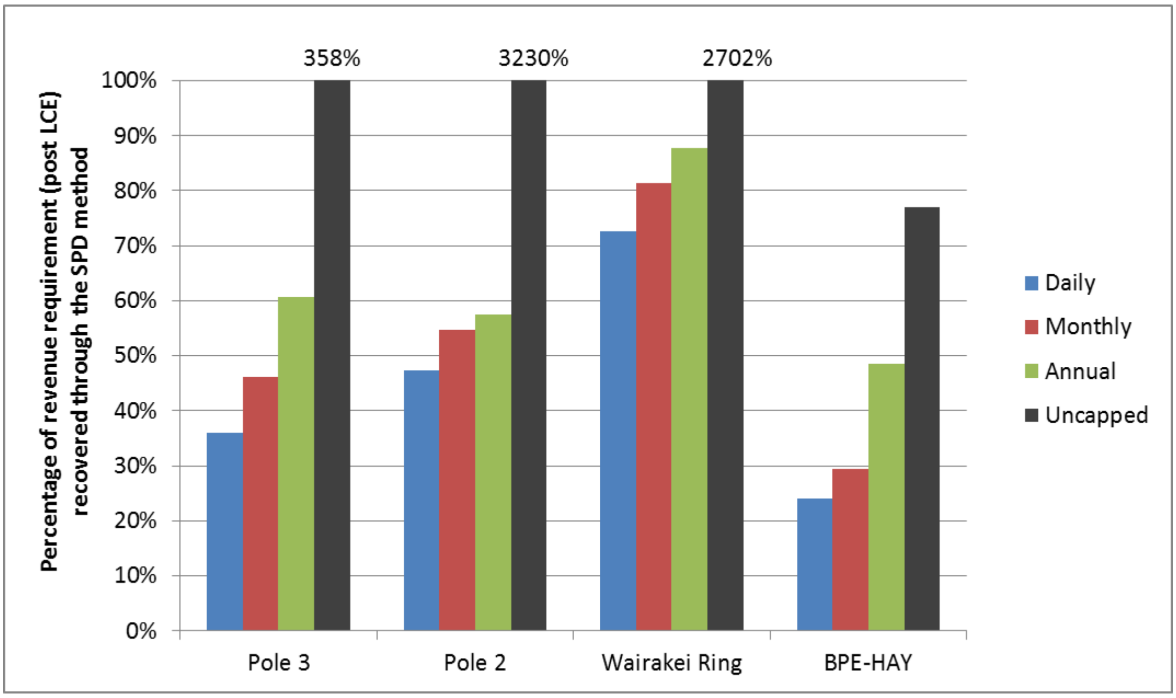
C.6 Note that modelling results illustrated in the figures below are in relation to Application A.

C.7 Increasing the length of the capping period:

(a) increases the amount of revenue recovered through the SPD method (Figure 18), but

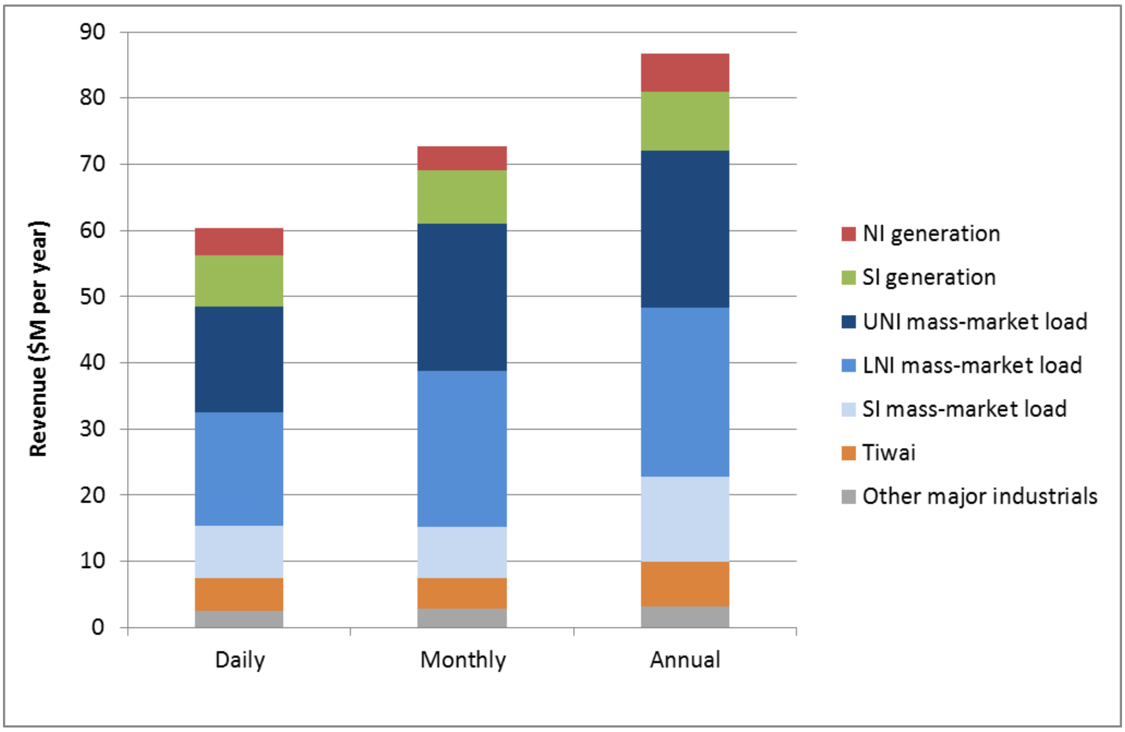
(b) also increases the incentive on parties to change their behaviour in response to the charge, which could be inefficient.

Figure 18: Effect of the capping period on the proportion of revenue recovered through the SPD method



C.8 The capping period also affects the breakdown of SPD charges between groups of parties (Figure 19).

Figure 19: Effect of the capping period on the breakdown of SPD charges across groups of parties



C.9 The selection of the appropriate capping period depends on which period best balances recovering revenue with avoiding inefficient behaviour. The Authority's preliminary assessment is that monthly capping provides the best balance.

C.10 The Authority intends to determine the extent to which quantified analysis could assist with the determination of the optimal capping period, as part of the development of the second issues paper, if the SPD option is considered further. This would also help inform the Authority of the potential detriments of the SPD option; particularly in view of some submitter concerns that generators could game the SPD charges.

C.11 The Authority would welcome comments on the best way to undertaken this analysis robustly, and any evidence submitters may have about the optimal SPD capping period.

Appendix D Heat maps showing the incidence of charges on load parties under each simulated option

D.1 This Appendix provides heat maps showing the incidence of simulated charges on load parties for Application A.[189] The data underlying these heat maps is provided at the following page on the Authority's website: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15374.

D.2 These heat maps (unlike the heat maps in the main text) include uplift in energy prices as a result of generators passing on transmission charges they incur. Three scenarios are included:

(a) a scenario in which there is no increment, that is, generators are deemed to be unable to recover the transmission charges they face by raising the price of energy

(b) a scenario in which the increment in energy prices is sufficient to recover 50 percent of the transmission charges incurred by grid-connected generators

(c) a scenario in which the increment in energy prices is sufficient to recover 100 percent of the transmission charges incurred by grid-connected generators.

D.3 For the purpose of preparing these heat maps, the uplift is assumed to be constant across time and space.

D.4 These heat maps exclude connection charges and revenues recovered through LCE.

189 Application B has not been modelled because charges under Application B are not expected to be materially different from status quo TPM charges for the modelled period (2017-2019).

Figure 20: Incidence of charges on load, in fully variabilised terms ($/MWh): Base Option, no generator pass-through

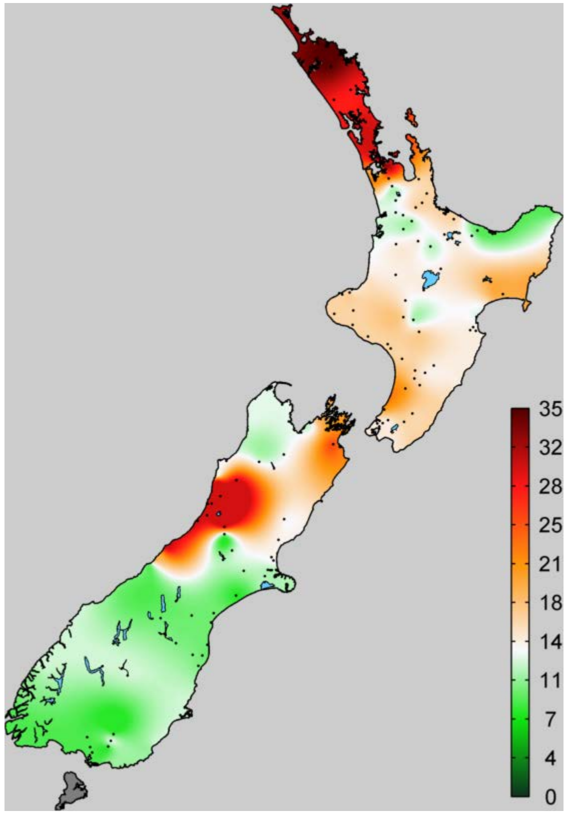


Figure 21: Incidence of charges on load, in fully variabilised terms ($/MWh): Base Option, 50% generator pass-through

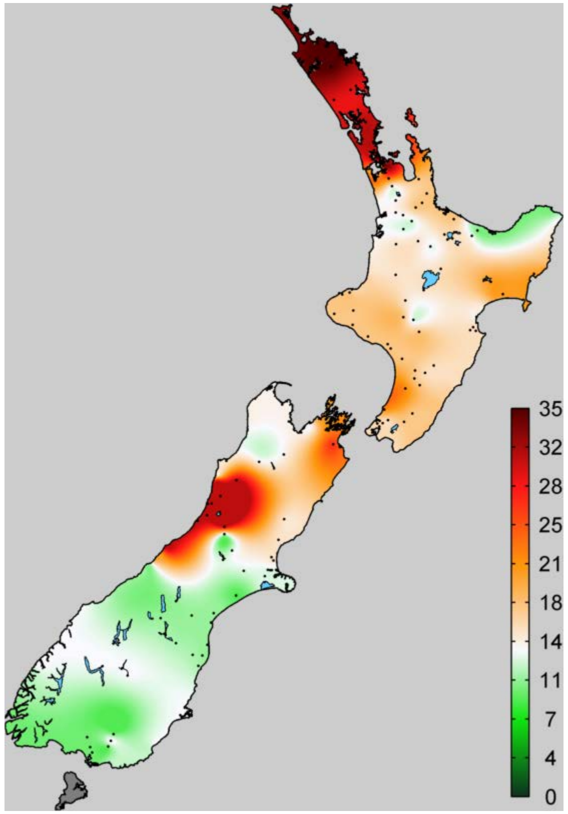


Figure 22: Incidence of charges on load, in fully variabilised terms ($/MWh): Base Option, 100% generator pass-through

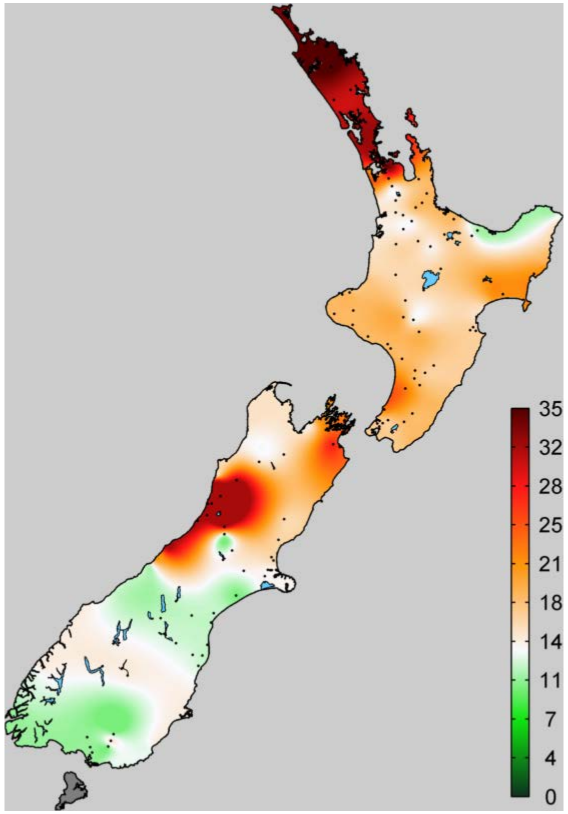


Figure 23: Incidence of charges on load, in fully variabilised terms ($/MWh): Base + LRMC, no generator pass-through

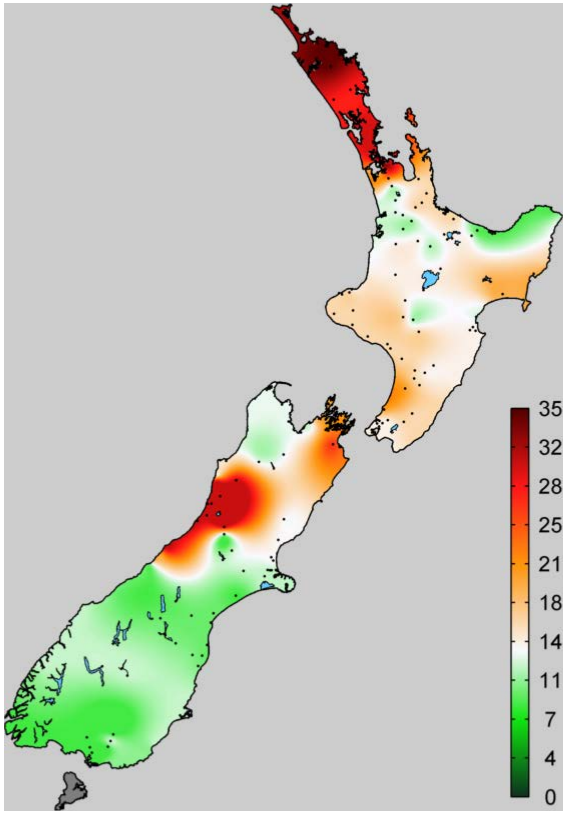


Figure 24: Incidence of charges on load, in fully variabilised terms ($/MWh): Base + LRMC, 50% generator pass-through

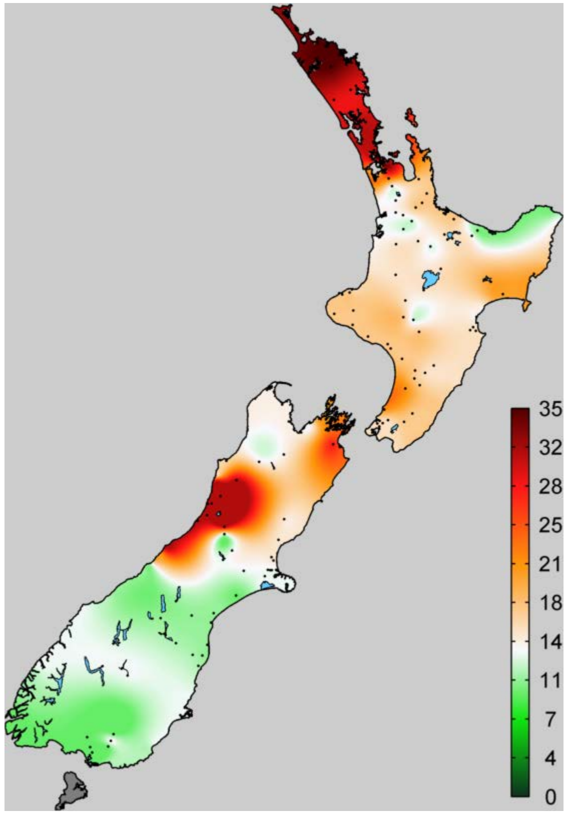


Figure 25: Incidence of charges on load, in fully variabilised terms ($/MWh): Base + LRMC, 100% generator pass-through

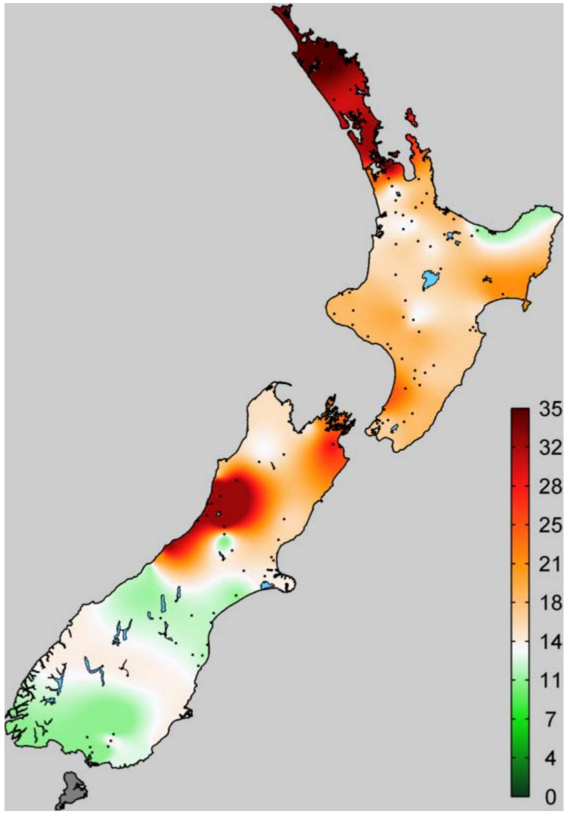


Figure 26: Incidence of charges on load, in fully variabilised terms ($/MWh):
Base + SPD, no generator pass-through

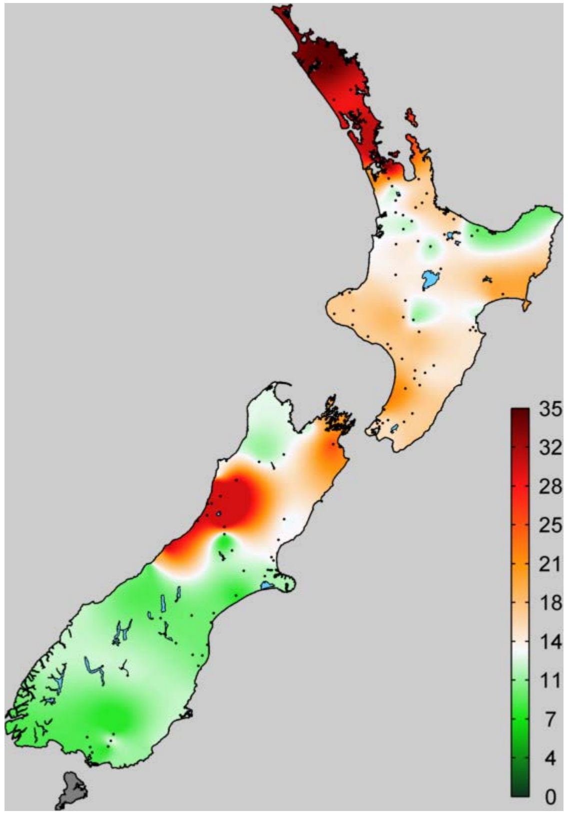


Figure 27: Incidence of charges on load, in fully variabilised terms ($/MWh):
Base + SPD, 50% generator pass-through

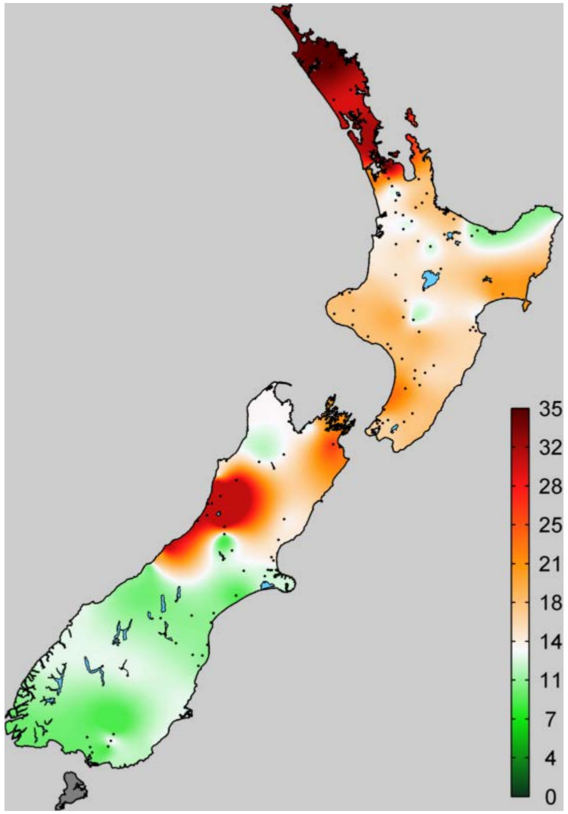


Figure 28: Incidence of charges on load, in fully variabilised terms ($/MWh): Base + SPD, 100% generator pass-through

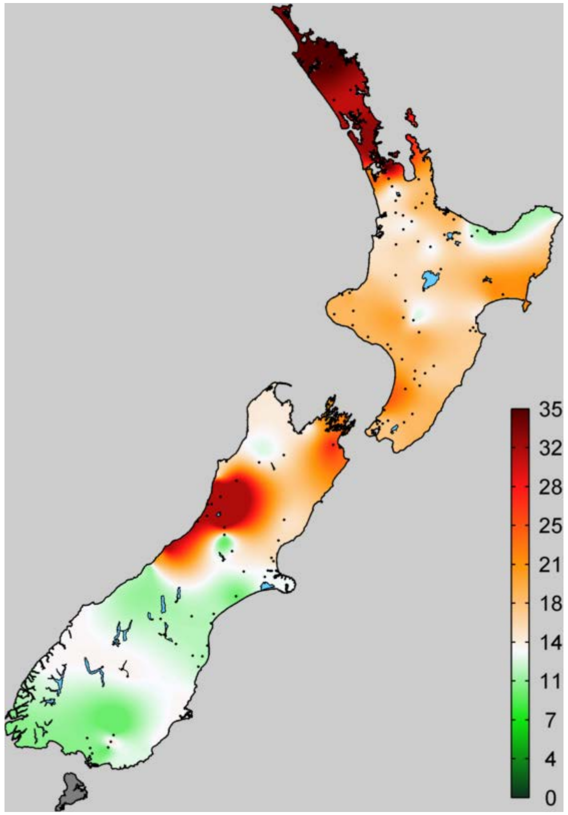


Figure 29: Incidence of charges on load, in fully variabilised terms ($/MWh): Status quo, no generator pass-through

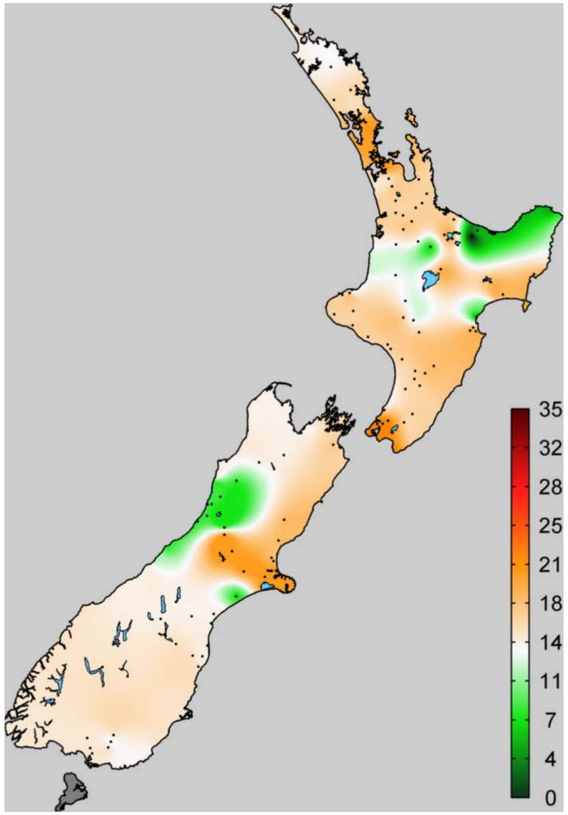


Figure 30: Incidence of charges on load, in fully variabilised terms ($/MWh): Status quo, 50% generator pass-through

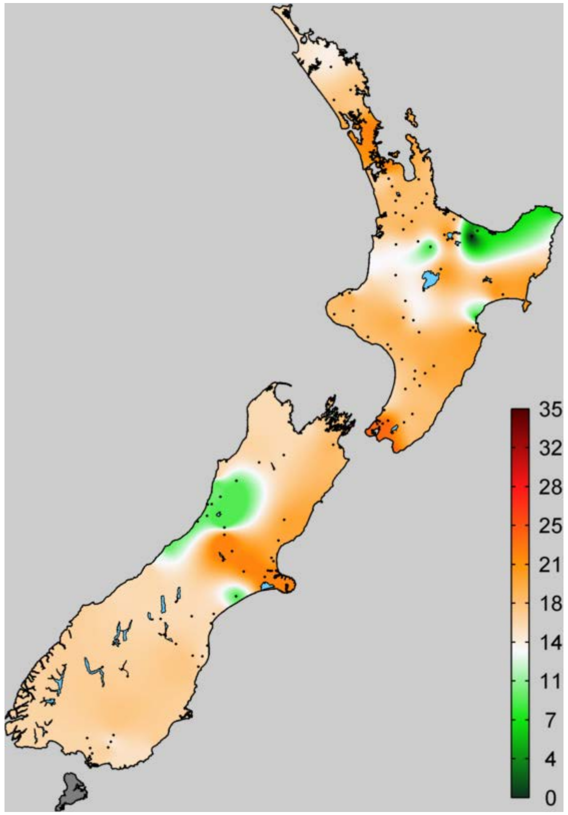
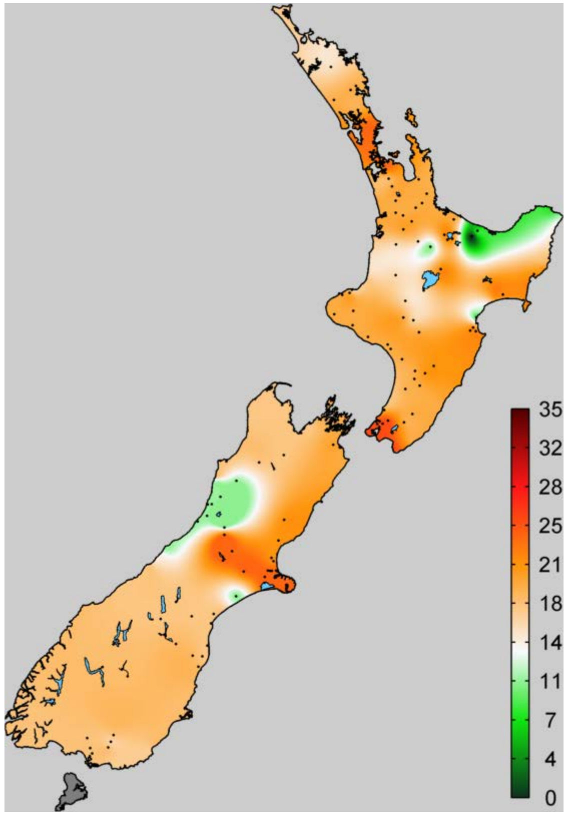


Figure 31: Incidence of charges on load, in fully variabilised terms ($/MWh):

Status quo, 100% generator pass-through



Appendix E Breakdown of the incidence of charges

E.1 All of the options involve the introduction of several new charges which would result in significant changes in prices for some parties.

E.2 To provide a sense of the magnitude of the change in charges (for Application A) under each option, Table 14 shows the modelled annual change in charges (excluding the kvar charge, connection charges and revenues recovered through LCE) to generation and load relative to the status quo for each option. All figures are based on an assumption that generators do not pass through any charges.

E.3 These tables exclude revenues recovered through LCE.

Table 14 Annual change in charges to generation and load, relative to the status quo, for each option under Application A, in $M p.a. terms

	Base Option	Base Option + LRMC	Base Option + SPD
NI generation	24	24	21
SI generation	-48	-43	-62
UNI mass-market load	133	131	142
LNI mass-market load	-11	-14	-4
SI mass-market load	-24	-22	-26
NZAS	-56	-55	-51
Other major industrials	-18	-18	-16

On mass market load, in $ per ICP per year terms:

	Base Option	Base Option + LRMC	Base Option + SPD
UNI mass-market load	198	196	212
LNI mass-market load	-13	-17	-5
SI mass-market load	-45	-43	-49

The figures above refer to the total charge divided by the number of active ICPs. Because they are averaged across both residential and commercial ICPs, they are likely to exceed the charge on a typical residential ICP.

In $/MWh terms:

	Base Option	Base Option + LRMC	Base Option + SPD
NI generation	0.9	0.9	0.8
SI generation	-2.9	-2.7	-3.8
UNI mass-market load	13.0 (1.3 c/kWh)	12.8	13.8
LNI mass-market load	-0.9	-1.2	-0.4
SI mass-market load	-2.5	-2.4	-2.7
NZAS	-10.9	-10.9	-10.1
Other major industrials	-4.1	-4.1	-3.5

Note: The figures above refer to:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for mass-market load.*

E.4 As Table 14 shows, the options would result in increases in transmission charges for some groups of customers – including upper North Island mass-market load and North Island generation – but decreases for other groups of customers – including most South Island mass-market load, South Island generation and most major industrial consumers.

Detailed breakdown by customer

E.5 The incidence of simulated charges in the scenario is shown in:

(a) Table 15a, in '$M per year' terms

(b) Table 15b, in '$ per ICP per year' terms, and

(c) Table 15c, in $/MWh terms.

E.6 Some geothermal power plants (such as Nga Awa Purua) are separated out for ease of reference.

E.7 Some industrial consumers are also separated out for ease of reference even though, in practice, their transmission charges might be paid indirectly through a network or retailer.

E.8 The modelled charges on EDBs in these Tables do not reflect that some EDBs make ACOT payments to embedded generators. As a result, 'status quo' charges may appear anomalously low (comparatively) for networks that include substantial amounts of embedded generation, relative to their amount of load (such as Top Energy or Westpower).

E.9 A key difference between the options is that South Island generators would pay less under Base Option + SPD than under the Base Option or Base

Option + LRMC. This is largely because they would pay a lower proportion of the cost of the HVDC under the SPD charge than under the AoB charge (based on the modelling assumptions described in Appendix A).

E.10 These tables exclude connection charges and revenues recovered through LCE.

Table 15a Modelled incidence of charges ($M per year)

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
EDBs					
Alpine Energy	8.33	8.22	8.22		10.92
Aurora Energy	19.49	19.14	18.69		20.77
Buller Electricity	1.71	1.87	1.72		1.65
Counties Power	13.17	13.06	13.03		7.14
Eastland Network	6.57	6.48	6.56		5.61
Electra	10.61	10.44	10.54		7.30
Electricity Ashburton	4.95	5.32	4.87		4.04
Horizon	5.21	5.19	5.45		2.78
Mainpower	8.30	8.13	7.97		9.48
Marlborough Lines	10.71	11.14	10.51		6.61
Network Tasman	11.84	11.92	11.53		11.48
Network Waitaki	2.87	2.85	2.78		3.70
Northpower	30.87	30.65	31.68		16.54
Orion	43.24	44.48	42.18		67.93
Powerco	81.04	79.91	82.50		74.31
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	16.52	15.99	16.33		21.86
Scanpower	1.47	1.45	1.50		1.62
The Lines Company	4.85	4.82	4.80		4.03
Top Energy	12.95	12.85	12.77		4.76
Unison *(incl Centralines)*	29.16	28.72	29.89		33.79
Vector	282.81	281.48	288.74		178.43
Waipa Power	5.04	4.91	5.28		6.67
WEL	18.83	18.62	19.29		21.55
Wellington Electricity	43.23	42.25	45.16		59.03
Westpower	8.99	9.10	8.92		2.39
Aggregate	682.77	678.99	690.93		584.40

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
Generators					
Contact	35.55	35.17	33.65		27.59
Fonterra *(Whareroa)*	0.21	0.21	0.29		0.18
Genesis	10.16	8.63	9.73		7.19
Meridian	49.08	53.81	38.56		92.19
Mokai JV	0.53	0.58	0.29		0.00
MRP	3.63	4.86	3.21		0.00
NAP JV	1.74	1.08	1.73		0.00
Ngatamariki	0.91	0.91	0.92		0.00
NZ Wind Farms	0.00	0.00	0.00		0.00
Pioneer	0.12	0.07	0.06		0.53
Todd	0.64	0.55	0.59		0.00
Trustpower	4.07	4.28	3.12		2.74
Aggregate	106.65	110.16	92.14		130.42
Major industrials					
CHH	1.45	1.43	1.91		4.41
Daiken MDF	0.19	-0.09	0.26		0.89
Kiwirail	0.16	0.15	0.20		0.47
Methanex	0.21	0.21	0.27		0.55
Norske Skog	1.13	1.37	1.06		0.00
NZ Steel	1.75	1.90	2.47		8.85
NZAS	7.61	7.83	11.66		63.22
Pacific Steel	1.06	1.09	1.40		3.62
PanPac	1.20	1.19	1.43		2.20
Rayonier	0.40	0.39	0.45		0.73
Winstones	0.40	0.39	0.63		3.63
Aggregate	15.58	15.87	21.74		88.58

Table 15b Modelled incidence of charges on EDBs ($ per ICP per year)

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
Alpine Energy	263	259	259		345
Aurora Energy	220	217	211		235
Buller Electricity	372	406	375		358
Counties Power	339	336	336		184
Eastland Network	259	255	258		221
Electra	246	242	245		169
Electricity Ashburton	270	290	266		220
Horizon	214	213	224		114
Mainpower	228	224	219		261
Marlborough Lines	435	452	426		268
Network Tasman	252	254	246		245
Network Waitaki	229	228	223		296
Northpower	560	556	575		300
Orion	233	240	228		367
Powerco	258	254	262		236
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	257	249	254		340
Scanpower	220	216	225		242
The Lines Company	211	209	208		175
Top Energy	421	417	415		155
Unison *(incl Centralines)*	250	246	256		290
Vector	519	516	530		327
Waipa Power	203	198	213		269
WEL	222	219	227		254
Wellington Electricity	258	252	270		353
Westpower	676	684	671		179

Note: The figures in Table 15b represent the total charge on the EDB divided by the number of active ICPs in the network area. Because they are averaged across both residential and commercial ICPs, they are likely to exceed the charge on a typical residential ICP.

Table 15c Modelled incidence of charges, on a fully variabilised basis ($/MWh)

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
EDBs					
Alpine Energy	10.9	10.7	10.7		14.3
Aurora Energy	14.0	13.7	13.4		14.9
Buller Electricity	14.7	16.0	14.8		14.1
Counties Power	27.1	26.9	26.8		14.7
Eastland Network	21.3	21.0	21.2		18.2
Electra	22.5	22.1	22.4		15.5
Electricity Ashburton	8.7	9.4	8.6		7.1
Horizon	9.9	9.8	10.3		5.3
Mainpower	15.7	15.4	15.1		17.9
Marlborough Lines	27.0	28.1	26.5		16.7
Network Tasman	14.4	14.5	14.0		13.9
Network Waitaki	11.6	11.5	11.2		14.9
Northpower	29.3	29.1	30.1		15.7
Orion	13.0	13.4	12.7		20.4
Powerco	17.7	17.5	18.0		16.3
PowerNet *(incl The Power Company, Electricity Invercargill, OtagoNet JV and Electricity Southland)*	11.0	10.6	10.9		14.5
Scanpower	16.0	15.7	16.3		17.6
The Lines Company	15.9	15.8	15.7		13.2
Top Energy	36.8	36.5	36.3		13.5
Unison *(incl Centralines)*	15.8	15.5	16.2		18.3
Vector	31.6	31.4	32.2		19.9
Waipa Power	12.7	12.4	13.3		16.8
WEL	14.2	14.1	14.6		16.3
Wellington Electricity	16.1	15.7	16.8		21.9
Westpower	30.5	30.8	30.2		8.1
Generators					
Contact	3.3	3.2	3.1		2.5
Genesis	1.3	1.1	1.2		0.9
Meridian	4.2	4.6	3.3		7.9
Mokai JV	0.6	0.6	0.3		0.0

	Base Option	Base Option + LRMC	Base Option + SPD		Status quo
MRP	0.7	0.9	0.6		0.0
NAP JV	1.5	0.9	1.5		0.0
Ngatamariki	1.4	1.4	1.4		0.0
Todd	1.1	0.9	1.0		0.0
Trustpower	2.0	2.1	1.6		1.4
Major industrials					
CHH	2.3	2.3	3.0		7.0
Daiken MDF	2.6	-1.2	3.5		12.1
Kiwirail	4.1	3.7	5.2		12.0
Methanex	4.5	4.5	5.9		12.0
Norske Skog	2.2	2.7	2.0		0.0
NZ Steel	1.7	1.9	2.4		8.6
NZAS	1.5	1.5	2.3		12.4
Pacific Steel	5.3	5.4	6.9		17.9
PanPac	2.3	2.3	2.8		4.2
Rayonier	7.0	6.8	7.9		12.7
Winstones	1.4	1.4	2.3		13.0

Note: The figures in Table 15c represent:

- *total charge divided by generation injection, for generators*
- *total charge divided by load offtake, for major consumers*
- *total charge divided by approximate gross electricity consumption, for EDBs.*

The figures for EDBs are comparable with those shown in the heat map plots in Appendix D.

Some generators with relatively small injection quantities are omitted.

Appendix F The effect of the options in this working paper on retail prices faced by typical residential consumers

F.1 This Appendix provides information about how Application A of the options described in this working paper could affect retail prices faced by typical residential consumers. Application B effects have not been provided because price effects are not considered likely to be significant for the modelled period (2017-2019). These figures **do not** take into account the effect of the transition alternatives discussed in Section 12. These transition alternatives would limit the level of changes to retail prices.

F.2 The impact would vary considerably from region to region. In this Appendix, network company areas are used to map out this variation.

F.3 The results in this Appendix are based on various assumptions and should be taken as indicative only. All figures are approximate. In order to produce more accurate estimates, it would be necessary to carry out additional analysis including investigating the current contribution of transmission charges to retail tariffs in each network area.

F.4 It is anticipated that any of the three options would deliver increased efficiency, which would result over time in lower transmission prices to consumers. Such efficiency effects are not considered in this Appendix – it focuses on the short-term redistributive effect.

F.5 The calculation below assumes that transmission charges are passed on from EDBs to mass-market load in fully-variabilised form.

F.6 Effects on commercial and industrial consumers, generators and other parties are not considered in this Appendix.

<u>Differences between regions</u>

F.7 For all three options, network company areas can be divided into four categories:

(a) network areas that would face considerably higher transmission charges on mass-market load than under the status quo – Top Energy and Westpower, averaging an estimated **2.3 c/kWh higher** than under the status quo

(b) network areas that would face somewhat higher transmission charges on mass-market load than under the status quo – Counties Power, Electra, Marlborough Lines, Northpower and Vector, averaging **1.1 c/kWh higher** than under the status quo

(c) network areas that would face roughly the same transmission charges on mass-market load as under the status quo – Aurora Energy, Buller Electricity, Eastland Networks, Electricity Ashburton, Horizon, Mainpower, Network Tasman, Powerco, Scanpower, The Lines Company, Unison (including Centralines) and WEL Networks

(d) network areas that would face somewhat lower transmission charges on mass-market load than under the status quo – Alpine Energy, Network Waitaki, Orion, PowerNet (including associated companies), Waipa Power and Wellington Electricity, averaging **0.45 c/kWh lower** than under the status quo.

F.8 A typical residential tariff, fully variabilised, can be assumed to be 24 c/kWh (excluding GST).[190] In relative terms, therefore:

(a) residential consumers in the *first* group of network areas above might pay a tariff approximately 10 percent higher under the three options than under the status quo

(b) residential consumers in the *second* group of network areas above might pay a tariff approximately 4.5 percent higher under the three options than under the status quo

(c) residential consumers in the *last* group of network areas above might pay a tariff approximately 2.0 percent lower under the three options than under the status quo.

F.9 These results differ very little between the three options considered. They are largely driven by the allocation of the deeper connection charge, which is common to all three options.

Generator pass-through is less significant

F.10 Retail tariffs are also affected by the change in the energy price faced by the customer. However, as will be shown, this is likely to be a second order consideration.

F.11 Table 16 shows the modelled average uplift in energy prices as a result of generators passing on the transmission charges they incur. As in Appendix D, three scenarios are included:

(a) in which there is no increment, i.e. generators are deemed to be unable to recover the transmission charges they face by raising the price of energy

(b) in which the increment in energy prices is sufficient to recover 50 percent of the transmission charges incurred by grid-connected generators

(c) in which the increment in energy prices is sufficient to recover 100 percent of the transmission charges incurred by grid-connected generators.

F.12 The table does not consider how the uplift may vary across time and space.

Table 16 – Simulated effect of generator pass-through on energy prices (in c/kWh terms)

	Base Option	Base + LRMC	Base + SPD	Status quo
With 0% pass-through	0.00	0.00	0.00	0.00
With 50% pass-through	0.12	0.11	0.09	0.16
With 100% pass-through	0.24	0.23	0.19	0.32

190 Quarterly survey of domestic electricity prices, http://www.med.govt.nz/sectors-industries/energy/energy-modelling/data/prices/electricity-prices/QSDEP-report.pdf

F.13 Suppose there is 50 percent pass-through of transmission charges. Then the contribution of pass-through to the customer's bill is 0.04 c/kWh lower under the Base Option than under the status quo option (comparison of yellow cells).

F.14 Suppose there is no pass-through of transmission charges under the status quo (as some have suggested), but the pass-through rate rises to 50 percent under the Base Option (as a result of more even distribution of charges across generators). Then the contribution of pass-through to the customer's bill is 0.12 c/kWh higher under the Base Option than under the status quo (comparison of cells with red text).

F.15 But both these differences are small compared with the differences in the incidence of charges between network areas that are shown above.

Appendix G Charging retailers versus EDBs

G.1 The Authority's October 2012 proposal[191] provided for charges on both generation and loads. For the residual charge on load, the Authority proposed that charges be allocated by default to direct connect customers and EDBs, but that EDBs could elect to opt out, in which case residual charges would be allocated directly to retailers.

G.2 Feedback from submitters was generally against charging retailers and the proposal to provide for EDBs to opt out of transmission charges. However, two EDBs and PwC on behalf of 22 EDBs supported the arrangement. Vector submitted that the opt-out proposal would create complex arrangements and residual charges should go to retailers by default.

G.3 The Authority consulted again on the question of retailers versus EDBs receiving transmission charges in the beneficiaries-pay working paper. Most of the submissions were against allocating TPM charges directly to retailers. The various submissions for and against charging retailers are provided in Table 17 below.

Table 17: Submissions for and against charging retailers

Submissions against charging retailers:	**Submissions for charging retailers:**
• increasing complexity for new retailers would reduce retail competition • no evidence has been provided to show charging retailers is more efficient • if charges are smoothed, there is no need to charge retailers (as EDBs can manage smoothed transmission charges) • charging retailers increases costs to retailers (for example, a Benchmark Agreement between Transpower and retailers, access regulation, distribution access arrangements, for example, prudential security, amendments to the definition of designated transmission customer) • practical implications such as	• EDBs would have problems complying with the Part 4 DPP/CPP price-paths if transmission charges aren't known ex ante, for example, under some LCE allocation and ex post SPD charge options • EDBs regulated by the Commerce Commission are able to pass transmission charges through. Retailers may be less capable of passing charges through • retailers currently lack incentives to engage in load control, for example, load control facilities on water heating. Charging retailers would provide such an incentive • depending on a EDB's pricing methodology, the price signal

[191] Electricity Authority, Transmission Pricing Methodology: issues and proposal, Consultation Paper, 10 October 2012.

adjusting for retailer entry and exit. Retailers are not permanent like EDBs • could adversely impact on the ACOT/distributed generation, for example, part of the avoided transmission charge would be smeared across all retailers	may be lost when EDBs pass TPM charges through to retailers

G.4 One of the key reasons the Authority had proposed that retailers would incur transmission charges directly was that half-hourly ex-post SPD charges that were part of the original 2012 proposals would have created complications for EDBs complying with their price-paths, and the Part 4 pass-through arrangements.

G.5 While the Authority continues to consider that there is strong justification for charging retailers in relation to SPD charges, the Authority notes that contestability is best promoted where EDBs incur or are required to pay the connection and deeper connection charges. For example, if EDBs receive efficient price signals they are efficiently incentivised to contract for their own connection and deep connection arrangements.

G.6 If deeper connection charges are implemented, the Authority notes that considerable cost recovery would come from EDBs.

G.7 Given that all options propose deeper connection charges, and this could constitute a large proportion of transmission revenue, and that significant costs would be involved in making retailers subject to transmission charges, the Authority's current position is that EDBs would continue to be subject to transmission charges.