Transmission pricing methodology: Use of LCE to offset transmission charges

Working paper

21 January 2014

Market Design

1 Executive summary

1.1 The Electricity Authority (Authority) is conducting a review of the Transmission Pricing Methodology (TPM) contained in schedule 12.4 of the Electricity Industry Participation Code 2010 (Code). The Authority is developing its response to submissions and cross submissions on the consultation paper 'Transmission Pricing Methodology: issues and proposal' dated 10 October 2012 (October issues paper), and to points raised in the May 2013 TPM conference.

1.2 The October issues paper included a proposal to amend the Code to require that loss and constraint excess (LCE) paid by the clearing manager to Transpower (as grid owner) be used to offset the components of Transpower's transmission charges that correspond to the origin of the LCE. Revenue to be recovered from transmission customers would therefore be net of any LCE received and apportioned to a particular asset.[1]

1.3 This is a market-based approach which, as outlined in the Authority's Decision-making and economic framework for Transmission Pricing paper[2], is the Authority's preferred approach for determining TPM charges.[3]

1.4 While in general submitters on the October issues paper were not opposed to this use of LCE, several submitters suggested that the application of LCE to the proposed transmission charge by asset would be inefficient. The Authority has identified and assessed the impact of the following two issues in terms of the effects on efficiency:

(a) **Muting of nodal price signals** – Some submissions on the proposed application of LCE argued that it would make nodal price signals less efficient by undermining the quality of the signals under current arrangements

(b) **Gaming risk** – In addition, some submissions and the Authority's Locational Price Risk Technical Group suggested that the proposed allocation of LCE could result in inefficient generator offer behaviour.

1.5 This paper concludes that the application of LCE proposed in the October issues paper, in conjunction with the other proposals in that paper, could mute nodal price signals, albeit in a limited and indirect manner. Generators would also take

[1] Electricity Authority Transmission Pricing Methodology: issues and proposal Consultation Paper, October 2012, paragraph 5.3.6.

[2] Electricity Authority, January 2012, Decision-making and economic framework for transmission pricing methodology consultation paper, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/.

[3] Note that the Authority decided in the October issues paper to use "market-based" as the generic term to refer to "market" and "market-like" approaches. See Figure 5 and footnote 42, Transmission pricing methodology: Issues and proposal: consultation paper, 10 October 2012. Further, the October issues paper uses the term "market approaches" to refer to approaches where prices are determined through a market, whereas such approaches were referred to as "market-based" in the decision-making and economic framework paper.

into account transmission charges in addition to all of the other inputs they currently take into account when developing their offers, and may have the incentive and ability to game the system by modifying their offers to take the treatment of LCE into account.

1.6 To the extent that these issues cause inefficiency, the design of LCE allocation may have an impact on overall efficiency of the revised TPM. Given this risk, the Authority has considered other methods for using LCE to offset transmission charges. These involve "crediting" LCE against the MAR[4] in an aggregated form.

1.7 The other approaches considered are:

(a) crediting LCE against the maximum allowable revenue (MAR) in bulk (option 1)

(b) classifying LCE by asset class and applying LCE originating from connection assets against charges for individual assets. Under this alternative, the remaining LCE would be credited against the MAR in bulk (option 2)

(c) classifying LCE by asset classes and applying LCE originating from connection assets against charges for individual assets. Crediting LCE from other asset classes against the MAR by asset class (option 3).

1.8 Of the options considered, the Authority's preferred approach is option 2.

1.9 The gaming risk in relation to connection assets is low. Connection customers lack incentives to take actions to increase LCE on these assets in order to reduce their transmission charges as such actions are likely to be counterproductive to them. On the other hand, crediting LCE to individual connection assets will avoid LCE originating from a particular asset being used to cross-subsidise the costs of other assets. Accordingly, the preferred option is to apply LCE derived from particular connection assets to charges for those assets.

1.10 With non-connection assets, some parties may have both the incentives and ability to inefficiently "game" the spot market to alter the creation and allocation of LCE in order to reduce their transmission charges. This may be at the expense of other participants. It is therefore proposed to credit remaining LCE against the remainder of the MAR rather than against specific assets. This would limit the identified risks of muting of spot market signals and inefficient gaming of the spot market. The Authority considers the benefits from avoiding gaming outweigh efficiency costs of LCE cross-subsidising costs between asset classes under this option.

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4 The TPM allocates Transpower's "full economic costs", which comprise the maximum allowable revenue set by the Commerce Commission under Part 4 of the Commerce Act 1986, plus pass-through costs and recoverable costs.

1.11 Using a long averaging period to calculate the distribution of LCE to assets or asset classes also goes some way to diminishing the risks of gaming. This could be applied equally effectively to all of the options considered.

1.12 The Commerce Commission sets the MAR. The Electricity Authority cannot, in the Code, amend the MAR. However, the Authority could (for example) specify that the MAR will be recovered first by payment of the LCE to Transpower (with a methodology for crediting shares of the LCE to each customer) and, second, recovered from customers according to a methodology specified in the TPM. Implementing the approach in the example above could involve amendments to the TPM and/or other parts of the Code.

1.13 Based on LCE amounts from 2009-2013, the Authority expects that LCE will account for $60M to $100M of transmission charges per annum, or approximately 5% to 11% of transmission charges on average over the near future.[5]

1.14 Practical considerations such as the timing of money flows and invoicing have not been considered in this paper and will need to be worked through in the detailed design of any changes to the TPM. However, it is considered that the same practical considerations are likely to apply to all of the options equally.

[5] See Table 4 in Appendix A of this paper for details on LCE quantity.

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2 Introduction

Background to process

2.1 The Electricity Authority (Authority) is reviewing the Transmission Pricing Methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of operating, maintaining, upgrading and extending the transmission grid.

2.2 The Authority considers that the current TPM can be improved so as to better meet the Authority's statutory objective to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Working papers

2.3 The Authority has decided to advance the process of reviewing the TPM by developing a second issues paper following consideration of submissions on the October issues paper[6] and information provided at the TPM conference held in Wellington on 29-31 May 2013.

2.4 Prior to developing a second issues paper, the Authority intends to develop and further consider key aspects of a revised TPM proposal through a series of working papers, which will input into the second issues paper.

2.5 This paper is the fourth of the series of working papers identified by the Authority. This working paper considers the use of LCE to reduce the size of transmission charges recovered by other means.

Background to this working paper

2.6 Loss and constraint excess (LCE) arises from three sources. The loss component arises because the nodal wholesale price paid by purchasers includes the cost of marginal losses at each grid exit point. The actual cost of losses is the volume of energy transmitted multiplied by the average loss factor. The constraint component arises because the marginal constraint price is paid by all consumption at a constrained grid exit point even though locational marginal pricing requires only that the last megawatt (MW) face this price. The third component (the reserves component) arises from price differences between the North and South Islands resulting from different prices applying for reserves in the two islands. In all three cases the amount collected from purchasers is greater than the amount required to pay generators. LCE is the difference between these amounts.

2.7 Until recently, LCE was distributed to lines companies and direct-connect consumers. With the introduction of a financial transmission rights (FTR) market, part of the LCE is used first for the settlement of FTRs. The residual LCE is the

[6] Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

amount remaining in the FTR account for a billing period that is not required to settle FTRs.

2.8 The Code requires the clearing manager to pay to Transpower (as grid owner) LCE and residual LCE. The Code requires Transpower to treat residual LCE in the same way as it treats LCE.[7]

2.9 Transpower's current allocation methodology involves allocating LCE to its customers that pay for assets in each of any one or more of three classes: AC connection assets, AC interconnection assets, and DC assets. In most cases, the LCE amounts are then rebated to consumers, either as direct rebates or indirectly as a reduction in overall distributor charges (which include the cost of transmission charges paid by the distributor). However, in some cases the LCE amounts are retained by the distributor.

2.10 In its October issues paper, the Authority proposed that the Code be amended to state that LCE received by Transpower be used to offset the components of Transpower's transmission charges that correspond to the origin of LCE. This is a market-based approach which, as outlined in the Authority's Decision making and economic framework for Transmission Pricing paper,[8] is the Authority's preferred approach for determining TPM charges. An outline of the Authority's hierarchy of approaches is shown in Figure 1.

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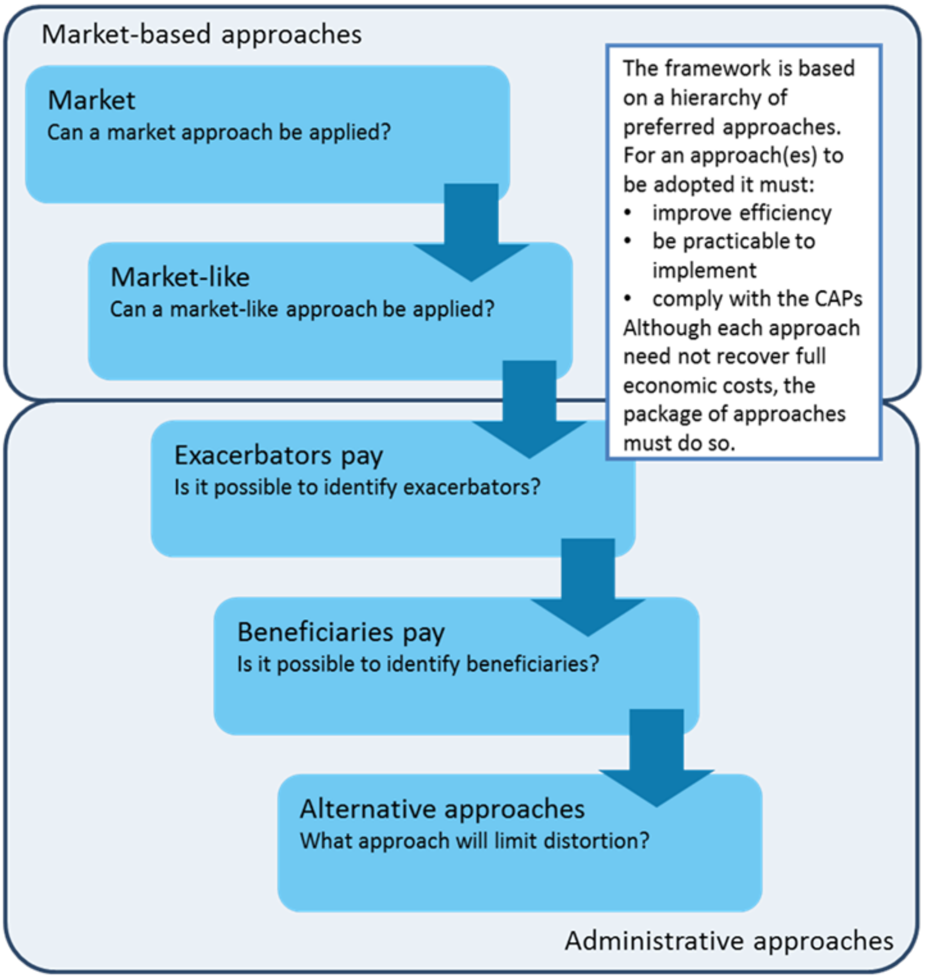
7 clause 14.73 of the Code.

8 Electricity Authority, January 2012, Decision-making and economic framework for transmission pricing methodology consultation paper, available at, http://www.ea.govt.nz/document/16502/download/our-work/programmes/priority-projects/transmission-pricing-review/. As noted in footnote 3, the Authority decided to replace the term "market-based approach" with "market approach" in the October issues paper.

Figure 1 Decision-making and economic framework for transmission pricing



Source: Electricity Authority

2.11 Revenue to be recovered from transmission customers would be net of any LCE originating from and apportioned to a particular asset. However, the proposal did not require that the Code specify the particular methodology that Transpower must use to apportion LCE to particular assets. Rather, the proposal was that the Code require that Transpower's methodology for allocating LCE originating from a particular asset must have the purpose of offsetting transmission charges to the customers of that asset.[9]

2.12 While in general this component of the proposal was well received, a number of submitters questioned the proposed treatment of LCE. In light of those submissions, this paper considers the original option, and other options that may better meet the Authority's objective.

9 October issues paper, paragraph 5.3.6. See also paragraph 4.8 of this paper.

Other working papers

2.13 Other working papers the Authority has identified include:

(a) Approach to CBA – This paper outlines a revised approach that the Authority intends to apply to the cost benefit analysis of the next TPM issues paper. (Submissions closed)

(b) The definition of sunk costs and the relevance of sunk costs to efficient production and pricing decisions. (Submissions closed)

(c) Avoided cost of transmission (ACOT) payments for distributed generation – This paper investigates the benefits and costs that result from payment of ACOT to distributed generation. This paper also determines whether or not ACOT payments to date reflect actual avoided costs of transmission. (Submissions close 5pm on 31 January 2014.)

(d) Approach to residual charge - This paper will consider whether it may be efficient to levy any residual charge on the basis of congestion rather than load during peak demand periods. (Future consultation)

(e) Beneficiaries-pay approach – This paper will examine options for applying a beneficiaries-pay charge. (Submissions close 5pm on 25 March 2014.)

(f) Connection charges - This paper will examine whether the pool charging approach for transmission connection assets is efficient and whether there is potential for connection assets to be inefficiently classified as interconnection assets. (Future consultation).

Decisions on the TPM

2.14 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Code must be consistent with the Authority's statutory objective. The TPM is part of the Code, so any amendments to the TPM must be consistent with the Authority's statutory objective.

2.15 To assist the Authority to make decisions about the TPM that are consistent with its statutory objective, the Authority developed a decision-making and economic framework.[10] The Authority applied this framework in formulating the proposals for the TPM set out in the October issues paper.[11] After considering submissions on the October issues paper and the responses of parties to the Authority's questions at the May 2013 TPM conference, the Authority has decided to develop and release a second issues paper which will include a revised TPM proposal and related guidelines (as referred to in clause 12.89 of the Code) to be followed by Transpower in developing a new TPM.

2.16 In developing the second issues paper, the Authority will continue to be guided in its decisions by its TPM decision-making and economic framework.

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[10] Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

[11] Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/

2.17 The Authority's Consultation Charter[12] sets out guidelines relating to the processes for amending the Code and the Code amendment principles that the Authority must adhere to when considering Code amendments.

2.18 The Authority will make decisions about the development of the TPM in accordance with its Code amendment principles and the Authority's statutory objective.

3 Purpose of this paper

3.1 The purpose of this 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.

Submissions

3.2 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 'Working Paper— Use of LCE to offset transmission charges' in the subject line.

3.3 If submitters do not wish 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

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

3.4 Submissions should be received by 5pm on Tuesday 4 March 2014. Please note that late submissions are unlikely to be considered.

3.5 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.

3.6 Your submission is likely to 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

12 Available from http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

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.

4 The current treatment of LCE

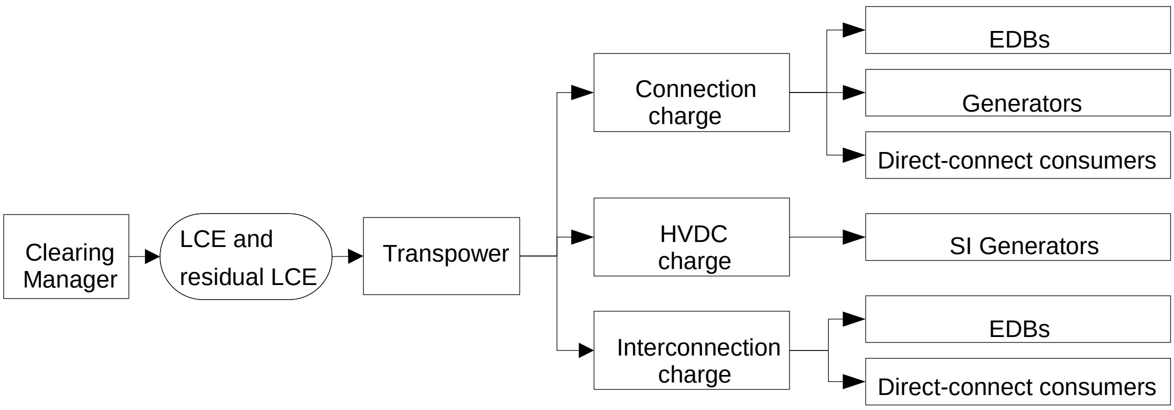
4.1 Transpower currently allocates LCE to its customers that pay for assets in any one or more of three classes: AC connection assets, AC interconnection assets, and DC assets. More information on the current treatment approach is attached as Appendix A.

4.2 Currently, the Code requires the clearing manager to pay LCE and residual LCE to Transpower (as grid owner). The Code also requires Transpower to treat residual LCE as LCE.[13] The Code does not, however, prescribe the methodology Transpower uses to distribute LCE, as discussed in the October issues paper.[14]

4.3 Transpower's current LCE allocation methodology is designed to ensure that LCE is, as far as possible, allocated to transmission customers based on overall purchase volumes, rather than, say, specific wholesale market outcomes. In this way the methodology attempts to preserve the investment and divestment signals nodal prices deliver.

4.4 The recipients of LCE are electricity distribution businesses (EDBs), generators, direct-connect consumers, and, in the special case of DC assets, South Island generators. This is illustrated in Figure 2.

Figure 2 Current recipients of LCE distributed by Transpower



Source: Electricity Authority

4.5 The treatment of LCE received by EDBs from Transpower varies. It is understood that over half the EDBs directly pass through LCE to retailers or large customers. Approximately 20% of EDBs split the allocation of LCE between passing LCE to retailers or large customers and applying LCE to Trust dividends. Around 10% of

13 Clause 14.73(5).

14 October issues paper, section 5.3.

EDBs use LCE as an indirect discount on network charges to their customers. The rest use a combination of these approaches.

4.6 Hogan in a 1991 paper set out the concept that the economically efficient allocation of LCE is through transmission rights that reflect the use of the grid by wholesale buyers and sellers of electricity.[15]

> *"By distributing the revenues obtained from short-run transmission usage back to the holders of transmission capacity rights, we would leave the costs of the transmission system to be collected from a set of fixed charges under long-term contracts. Combined with short-run marginal cost prices, the fixed charges are economically efficient as the other half of a two-part tariff and would fall naturally to the recipients of the transmission rights. Customers who wish to reduce the costs of congestion implicit in payments in the electricity spot market would have an incentive to invest in transmission expansion and reinforcement. Such investment would create new transmission capacity. The right to the financial benefit of that new capacity could be assigned to the customer who agreed to pay the investment cost. Those who invest in long-term transmission capacity rights would not face the possibility of later paying congestion costs induced by other users of the system. This provides the complementary long-term financial assurances found in the companion long-term energy contracts. These long term contracts provide the necessary analogy to property rights to promote economically efficient incentives for long-term investment in both generation and transmission."*

4.7 Hogan's point is that the economically efficient treatment of LCE is to use LCE to fund the holders of transmission rights, leaving the fixed costs of transmission to be recovered from the users (beneficiaries) through some alternative methodology.

4.8 One form of transmission capacity rights is known as a financial transmission right (FTR), which can be allocated through an FTR market. An FTR regime has been incorporated into the Code and a market for FTRs has now begun trading in New Zealand.

4.9 The FTR regime is based on nodes at Otahuhu and Benmore. It is anticipated that some 60-70%[16] of total LCE will first be allocated to fund the FTR market. If the combined FTR auction proceeds and LCE exceeds the amount required to settle FTRs, the remaining amount in a billing period (residual LCE) must be paid

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15 William W Hogan Transmission capacity rights for the congested highway: A contract network proposal submitted to the Federal Energy Regulatory Commission in response to notice of public conference and request for comments on electricity issues June 8, 1991.

16 Energy Link prepared for the Electricity Authority **Losses and Constraints Excess Projections** "In 2025/26, if all HVDC constraints are included then 67% of all modelled constraints are caused by the HVDC link or the BHEQ."

to Transpower. Transpower must allocate the residual LCE in the same way that it allocates LCE.

4.10 The Authority has consulted on the possibility of an expanded FTR market and has requested the FTR manager develop the FTR market with new nodes (or hubs) at Haywards, Islington and Invercargill, and only add FTRs between additional points if certain criteria are met.[17]

4.11 The expansion of the FTR market is likely to mean an increase in the amount of LCE that is first allocated to fund the FTR market.

4.12 Despite the introduction of FTRs, the amount of LCE paid to transmission customers is still likely to be volatile due to the allocation and FTR processes. This means there is only a loose correlation between LCE and spot market outcomes.

17 Electricity Authority letter to the FTR manager http://www.ea.govt.nz/our-work/programmes/priority-projects/locational-hedges/within-island-basis-risk/ 25 October 2013.

5 Submissions on proposed methodology for allocating LCE

The question asked

5.1 A number of submitters questioned the method for allocating LCE proposed in the October issues paper. That paper proposed that LCE would be allocated based on the origin of the LCE. The question asked regarding the LCE component of the proposal in the October issues paper was:

> *"What is your position on the Authority's proposal to codify that LCE or residual LCE received by Transpower from the clearing manager is to be used to offset the components of Transpower's transmission charges that correspond to the origination of the rentals"*

5.2 A full summary of submissions on the October issues paper and a full transcript of the conference discussion are available at the Authority's TPM review project webpage[18]. This working paper provides a brief breakdown of distinct points made by submitters, and then provides an overview of two key criticisms made by submitters on the method for allocating LCE proposed in the October issues paper.

Overall support to use LCE to offset transmission charges

5.3 Most submitters supported the Authority's concept of using LCE as a market-based source of revenue to offset transmission charges.[19]

5.4 Twenty one submitters commented on the Authority's LCE proposal. Out of those commenting, 13 submitters either supported the proposal or broadly supported the concept of the proposals. Eight submitters did not support the proposal.

5.5 Table 1 below summarises some of the distinct points made by submitters and the number of submitters who clearly made these points. A number of these points were discussed at the May 2013 TPM conference.

Table 1 Submissions on proposed methodology for allocating LCE

Submissions	Number of submitters
Opposed to LCE being allocated to specific assets.	*5*
In favour of LCE being credited against MAR in bulk (i.e. reduce the residual charge).	*7*
Proposed approach doesn't match overall TPM approach.	*1*
Proposed approach would dilute wholesale price signals to	*3*

[18] Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

[19] Electricity Authority *Summary of submissions Transmission Pricing Methodology: issues and proposal consultation paper* 28 May 2013.

consumers.	
Prefer LCE to go back to loads that paid for it in the first place.	*2*
Consider that there are more efficient uses to which LCE could be applied	*2*

Source: Electricity Authority

Key issue 1: Dilution of nodal pricing signals

5.6 The following comments represent a selection of submitters views regarding the perceived issue of dilution of nodal pricing signals:

Electricity Networks Association (ENA)

"*The ENA supports in principle the proposed use of residual LCE to off-set against transmission charges. However we do not support the proposed method to do so in a way that aims to off-set the LCE to the assets and participants that generated them, as this approach would negate (or at the least reduce) the otherwise efficient wholesale market signals related to losses and congestion.*" [20]

Fonterra

"*The purpose of the loss and constraint rental is to change consumer behaviour as it increases the price to indicate that the line is constrained.*

If this rental is placed back against the individual asset, then it could result in the consumer no longer receiving this pricing signal, and may in fact decrease the allocation at that point." [21]

Norske Skog

"*This would appear to water down nodal pricing signals to constrained areas, thus disincentivising consumers from taking action to alleviate the constraint.*" [22]

Transpower

"We do not support this proposal because it would have the effect of muting nodal pricing signals, which would reduce the efficiency of those signals." [23]

Key issue 2: Offer behaviour

5.7 Mighty River Power suggested that the method for allocating LCE proposed in the October issues paper would impact generator offers and stated:

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20 Electricity Network Association submission page 7.
21 Fonterra submission page 6.
22 Norske Skog submission page 10.
23 Transpower submission page 16.

> *"We question the need to use LCE to offset transmission charges on an individual asset basis for HVDC/interconnection assets. This can lead to complexities such as* ***increased loss and constraints across interconnection/HVDC assets reducing the transmission charges some participants would pay via the SPD method and the residual for those assets****. Thus when parties structure their bids/offers they will have to consider not just wholesale market price impacts in a trading period but also SPD/residual charge impacts net of LCE rebates, all across a number of assets."* [24]

5.8 This was a view that was shared by the Authority's Locational Price Risk Technical Group, which raised the possibility that offer behaviour may change as a result of the method for allocating LCE proposed in the October issues paper.[25] The concern is that generators might alter their offers to increase LCE on assets in relation to which the generator expected to pay transmission charges, to minimise the transmission charges faced.[26]

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24 Mighty River Power submissions, Appendix A, page 5.

25 Note that this issue was also highlighted during development of the FTR market as LCE arising on the HVDC is paid to SI generators. This is a reason why the current TPM is problematic and is under review.

26 Note that although the LCE charge and the originally proposed SPD charge are driven by spot market outcomes, one does not offset the other, leaving opportunity for manipulation of one or other (or both) by participants to maximise profits. Both this paper and the beneficiaries-pay working paper have developed approaches to minimise these risks.

6 Key issue 1: Muting of nodal price signals

Adoption and effectiveness of full nodal pricing

6.1 It is important to provide some context before considering whether the treatment of LCE, as proposed in the October issues paper, undermines efficient nodal price signals in any significant way.

6.2 In 2002, the NZEM Rules Committee commissioned a study on the effectiveness of full nodal pricing.[27] This study reported:

> *"The FNP (Full Nodal Pricing) regime was adopted when New Zealand's wholesale market was established in October 1996. A key consideration in adopting nodal pricing for the NZEM was its consistency with the efficiency goals that had driven the restructuring and reform of the market.*
>
> *The FNP regime applied in the NZEM establishes the price of providing energy at each grid injection and exit point on the transmission network. Nodal prices represent the change in the total cost (as represented by market participants' bids and offers) of meeting system energy requirements caused by a change in load or generation at each node. Therefore, in the NZEM, nodal prices incorporate the effects of power losses and line constraints on the total cost of meeting system load requirements.*
>
> *In theory FNP signals ensure that:*
>
> - *in the short-run electricity is allocated to its highest-value uses (allocative efficiency); and*
> - *in the long-run the timing and location of new investment ensures continued allocative efficiency (dynamic efficiency)."*

6.3 Professor Hogan explains nodal pricing as the convergence between the physics of electricity and establishing price signals on an electricity system[28]:

> *"A single transmission constraint in an electric network can produce different prices at every node. Simply put, the different nodal prices arise because every location has a different effect on the constraint. This feature of electric networks is caused by the physics of parallel flows.*
>
> *There is nothing unusual in nodal pricing. It is the natural system that falls out of an analysis of competitive market marginal-cost pricing principles in the context of the physics of the electric network. Nodal pricing does not solve all problems in electric market design, but it turns out to be important in dealing with some of the most intractable problems created by the special nature of*

27 NZEM Rules Committee. Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM November 2002.

28 William Hogan Transmission Congestion: The Nodal-Zonal Debate Revisited February 27, 1999.

the electric grid… practical experience and theoretical analysis both support the conclusion that for the independent system operator, nodal pricing is the simplest system that actually works in the context of a market with choices and flexibility.

Get the prices right, and it is much easier to rely on the market."

6.4 The NZEM assessment of outcomes compared actual and expected outcomes across five categories:

(a) efficient short-run operation

(b) efficient long-run operation

(c) ability to manage risk

(d) effective retail competition

(e) competitive price discovery.

6.5 A summary of the relevant conclusions from the paper are:

(a) FNP provides an efficient means by which generation is ordered for efficient physical dispatch and determination of a spot price

(b) FNP influences generation decisions, but is only one of many influencing factors.

6.6 These conclusions are consistent with Professor Hogan's point that FNP does not solve all the problems in "electric market design but that FNP addresses some of the most intractable problems created by the physical characteristics of the electricity grid."

6.7 The working assumption then is that nodal price signals support efficient prices. The question for this paper is whether the treatment of LCE as described in the October issues paper undermines efficient pricing signals in any significant way.

Treatment of LCE as proposed in the October issues paper on nodal price signals

6.8 The proposed treatment of LCE paid by the clearing manager to Transpower (as grid owner), as described in the October issues paper was that the revenue to be recovered from transmission customers is net of any LCE received and apportioned to a particular asset. The proposal would not directly impact on the determination of prices at each node, nor would it directly impact on the nodal price in the wholesale market.

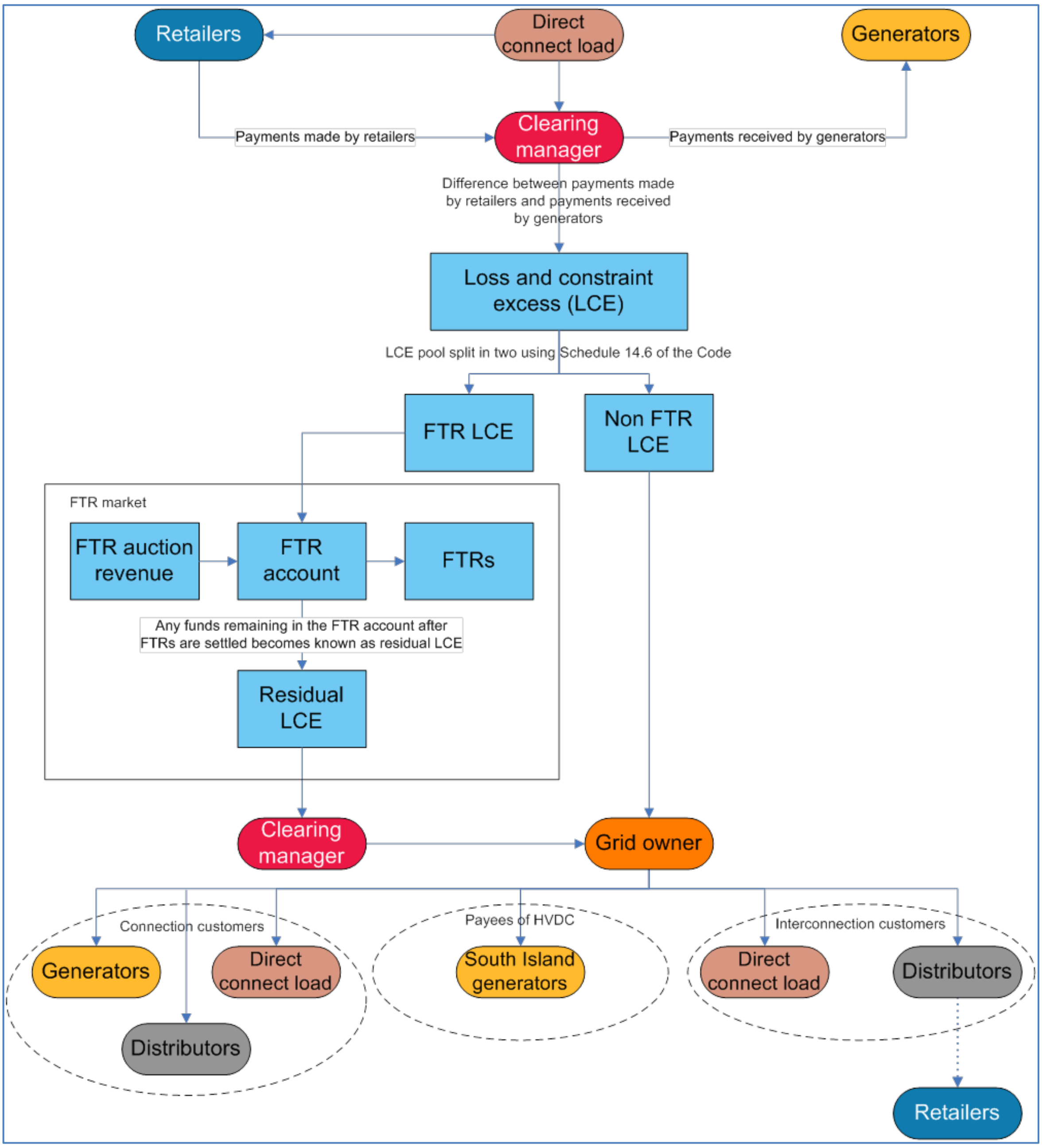
6.9 Retailers, generators and direct connect consumers are exposed to direct nodal price signals. Consequently, retailers may change their charges to consumers to reflect changes in nodal prices. However, the extent of such change is mitigated by the fact that invoices to consumers typically cover a period of 1-3 months. LCE is only one of a number of charges included.

6.10 Direct-connect consumers are more exposed to nodal price signals than retailer consumers because these consumers receive separate invoices for energy and network charges.

6.11 The current spot market and LCE flows are shown in Figure 3. Figure 3 shows that LCE is routed either to the FTR account or to distributors or direct-connect consumers through the allocation of LCE by Transpower. Any residual LCE (the amount remaining in the FTR account for a billing period that is not required to settle FTRs) is paid to Transpower. Transpower must treat residual LCE in the same way that it treats LCE. Transmission charges calculated under the current TPM do not specifically contain any direct energy market signals.

6.12 Figure 3 also shows that, under the status quo, some of the parties participating in the spot market and receiving LCE (either directly or indirectly via distributors) are the same: generators, retailers and direct-connect consumers.

Figure 3 Spot market and LCE financial flows under status quo

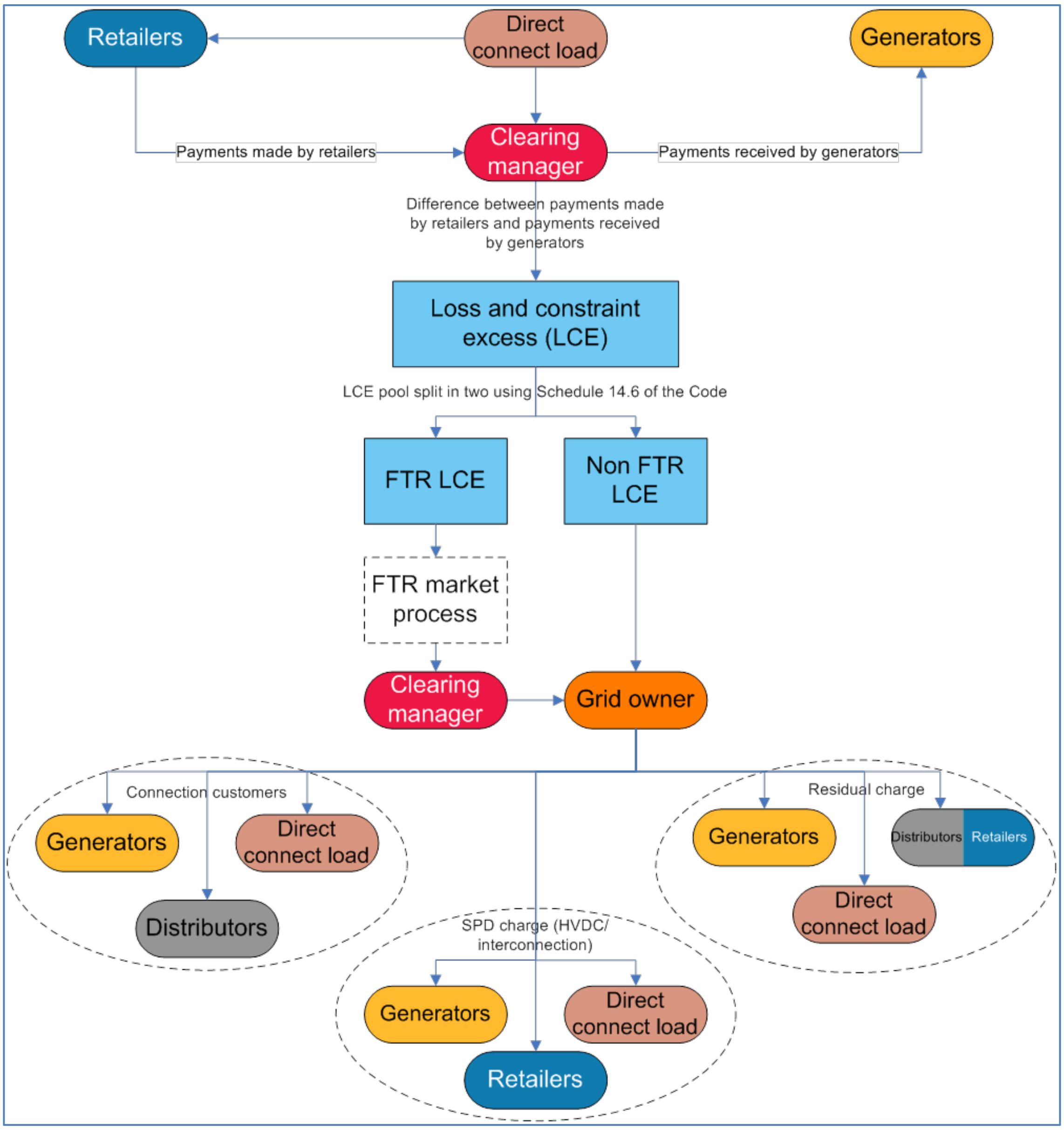


Source: Electricity Authority

6.13 Under the proposal in the October issues paper the LCE flows and the beneficiaries-pay-based price signals would change to reflect that LCE would have been applied to the transmission cost. This means that beneficiaries are exposed to the net transmission cost.

6.14 Under the proposal in the October issues paper the parties paying transmission charges changes. In particular, generators, direct connect consumers and retailers would be subject to the SPD charge. These parties would also have been subject to residual charges (regional coincident peak demand (RCPD) and injection (RCPI) charges), except in the case of retailers on networks where the distributor had elected not to opt out of the charge, in which case the distributor would have been subject to the charge.[29] This is shown in Figure 4.

Figure 4 Spot market and LCE financial flows under October 2012 proposal



Source: Electricity Authority

6.15 Figure 4 shows that under the proposal the parties that would have been exposed to the allocation of LCE, through its use to offset transmission charges, broadens. In particular, all generators, along with direct connect consumers and retailers, would be exposed to the use of LCE to offset HVDC and

29 the October 2012 TPM proposal only proposed to retain RCPD charges and adopt RCPI charges if doing so was efficient

interconnection costs. Figure 4 shows that these are also the parties participating in the spot market.

6.16 The bulk of consumers pay a combined lines and energy bill. The lines charge would be made up of distributors' costs and the transmission charge. As proposed in the October issues paper the transmission charge will be the charge net of any LCE. The retailer's energy charge will be the same except to the extent wholesale prices change to reflect the introduction of the TPM.

6.17 For direct-connect consumers the same applies as for mass market consumers except the two parts of the invoice (energy and transmission/distribution) are separate.

6.18 Under the proposed guidelines set out in the October issues paper a beneficiaries-pay charge would be introduced. This charge would change the nodal price signals as there would be an alignment between the energy market signals and transmission charges in a way that has not been the case previously. The proposed application of LCE in the October issues paper would contribute to this change albeit in a limited and indirect manner. In summary:

(a) With the exception of the HVDC link, there is currently only an indirect relationship between LCE originating from an asset and the transmission charges paid in relation to that asset. Under the proposal, there would be a more direct relationship between LCE originating from an asset and transmission charges for that asset, because the LCE would directly determine the transmission charges that would apply

(b) Some beneficiaries-pay charges, such as the SPD charge, would link spot market outcomes to transmission charges for the beneficiaries-pay component of the charge. However, the strength of the linkage would depend heavily on the approach applied to calculating benefits. There would be a direct relationship between the SPD charge and spot market outcomes since spot market outcomes would be used to determine the benefits a party received from an investment and therefore the charge they faced. However, the directness of this relationship would depend on the parameters chosen. Adopting a monthly or annual ex ante billing method may address these issues, and the same would apply if LCE was allocated to asset classes on a monthly or annual basis

(c) The proposal to apply LCE in relation to charges for the particular asset on which the LCE originated would also link effective transmission charges to spot market outcomes. However, LCE is highly variable and not strongly correlated with benefits of transmission that would be reflected in beneficiaries-pay charges that rely on wholesale market outcomes, such as the SPD method

(d) The transformation process applied to LCE via the FTR market would reduce this linkage further.

6.19 In conclusion, there is a risk that allocating LCE to offset costs of individual transmission assets may dilute nodal price signals. While this risk may be small it cannot be ruled out entirely. It should therefore be taken into account in the design of any methodology that changes the allocation of LCE.

7 Key issue 2: Gaming risk

7.1 The Locational Price Risk Technical Group and some submitters in response to the October issues paper expressed some concern that generators might alter their offers to increase LCE on the assets for which they expect to be paying transmission charges under the original proposal. If generators did this, it could result in inefficiencies.

7.2 To assess whether generators are likely to alter their offers in this way, this section addresses the question of whether the approach described in the October issues paper would create an incentive and allow participants to alter their wholesale market offer behaviour to reduce their overall transmission charge.

Role of generator offers[30]

7.3 In the wholesale electricity market:

(a) all energy offers (along with reserve offers and forecast demand) are used to determine dispatch order after adjusting for location

(b) the wholesale price in any half hour is based on the marginal generator’s offer

(c) all generation offered below the marginal generator after adjusting for location receives the marginal price.

7.4 On that basis, generators’ main long-term objective for their offer strategy is broadly to maximise half hourly net settlements.

7.5 Generators may also take into account other factors, such as availability of fuel, resource consent requirements and plant flexibility. Notwithstanding those other factors, the high level factors taken into account by generators when determining offer strategy are set out in Table 2.

Table 2 Components of a generator's settlement calculation each trading period

Elements factored into offer strategy
Expected receipts from generation.
Expected purchase costs to cover retail load.
Expected receipts from reserve offers.
Expected payments for reserve availability

30 This paper looks exclusively at generator offers. However, with the introduction of dispatchable demand, there is potential for similar incentives to apply also to demand bids. Parties that may make demand bids currently pay interconnection and connection charges, and under the proposal in the October issues paper would have also been subject to the SPD and RCPD charges.

Payments and receipts that may arise if reserve is called.
Receipts or payments against financial contracts (CFDs, options, futures, FTRs) based on forecast wholesale prices.
Impact of wholesale prices on retail tariffs. This is not variable on a half hourly basis but wholesale price trends and wholesale price volatility feeds into retail tariffs over time.
Under the current TPM, expected HVDC charge payments (SI generators).
The potential effect on wholesale prices and reserve prices of constraints binding.

Source: Electricity Authority

7.6 Currently, generators have no incentive to take LCE into account in formulating offers, with the exception of South Island generators with regard to the HVDC.

7.7 While traders are likely to be disciplined about their offer strategies in each trading period there is still room to craft offers to take into account events that might occur unexpectedly or to create competitive effects. The Code does not directly inhibit the level of offers (apart from imposing a minimum quantity) or the factors that must be considered when offers are formulated.

7.8 The proposal in the October issues paper to apply LCE to charges for the individual assets from which the LCE originated means that spot market outcomes could have an effect on transmission charges.

7.9 Although both LCE and the SPD charge are driven by spot market outcomes the drivers are quite different in each case. The LCE for a particular grid asset is driven by differences in nodal prices across transmission links in the real spot market (i.e. with all grid assets in play). In contrast, the SPD charge for that grid asset is driven by differences in nodal prices and quantities in the real spot market (all grid assets are in play) versus nodal prices and quantities in a counterfactual spot market (where the grid asset is hypothetically removed from the market). These differences mean generators could adjust their spot market offers to maximise LCE and minimise SPD.

7.10 Thus LCE originating from an asset for which a generator is liable for transmission charges would likely become a consideration in determining a generator offer.

7.11 Generators would therefore have an objective to optimise the revenue impact of spot market outcomes combined with transmission charges including LCE allocation applicable to the generator organisation.

Changes to offer strategy to take into account the proposed treatment of LCE

7.12 This section has described how traders may formulate their offer strategy by simultaneously optimising spot market outcomes and transmission charges.

7.13 The possibility exists that generators would take into account LCE specifically, and any FTRs held, in a way that affects pricing outcomes. The extent to which they would have incentives to do this will depend on their transmission charge for an asset, the LCE that could result on that asset, and the overall impact on their profitability of a strategy that sought to increase LCE.

7.14 An example of such a strategy would be for a generator in an AC region subject to both import and export situations to alter their offers to cause import constraints to occur more frequently than would otherwise occur. The constraints would lead to increased LCE. If this were to be allocated against specific assets then the generator could offset the costs it incurred through this strategy by facing a reduced beneficiaries-pay charge when it uses the assets to export from the region.

7.15 While the risk of a participant successfully applying such a strategy is likely to be minimal, that risk has to be taken into account in deciding on the method of allocating LCE.

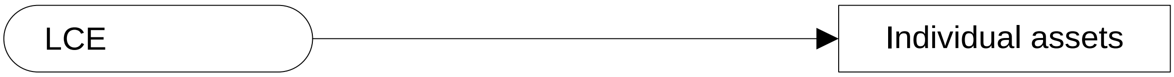
7.16 One approach to mitigating these risks may be to alter the averaging period over which LCE is allocated to assets. For example if a monthly or annual averaging period were used then the linkage between spot market offers and LCE receipts would be weakened.

8 Alternatives to original proposal

8.1 Currently, Transpower allocates LCE it receives to three classes. Broadly, LCE allocated to an asset class is rebated to transmission customers in proportion to the transmission charges that the customers pay in relation to that asset class.

8.2 In the October issues paper, the Authority proposed that the Code be amended to state that LCE received by Transpower be used to offset the components of Transpower's transmission charges that correspond to the origin of LCE, by particular asset.[31] This is illustrated in Figure 5 below.

Figure 5 Original proposal to guide Transpower's treatment of LCE as proposed in the October issues paper



Source: Electricity Authority

8.3 As identified in section 6, the Authority's proposal for allocation of LCE in the October issues paper raises a risk of dilution of nodal price signals. Section 7 identified there is a risk of generators altering their offer behaviour in response to the proposed LCE allocation. This section considers three other options to address these issues and makes a recommendation on a preferred option.

Option 1: Crediting LCE against MAR in bulk

8.4 Under option 1, all LCE would be credited against the MAR recovered under the TPM with no distinction made between the asset classes or assets in relation to which LCE originated. Option 1 is illustrated in Figure 6 below.

Figure 6 Option 1: Credit LCE against MAR in bulk

Source: Electricity Authority

8.5 LCE would be paid to Transpower on the basis that LCE could be used to fund on-going costs and investment in transmission. This would be a market-based approach to recovering Transpower's costs, and therefore the most preferred charging approach under the Authority's decision-making and economic framework under the TPM. However, because grid investment does not exhibit constant returns to scale, LCE is insufficient to fully fund the TPM. This would be in contrast to Transpower's current approach of recovering transmission charges under the TPM whilst at the same time allocating LCE to transmission customers.

31 Consultation paper, paragraph 5.3.6.

Option 1 reflects the possibility that the money flow under the current arrangements may not be efficient.

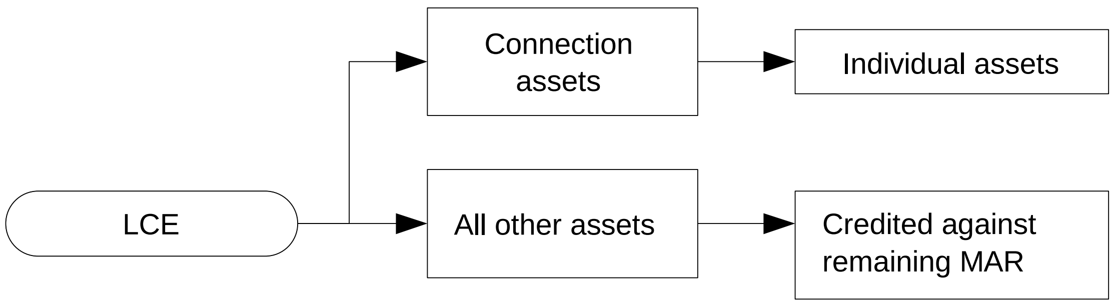
8.6 Under option 1, LCE originating from particular assets would not necessarily offset the charges for those assets directly. On that basis there may be a wealth transfer between payers for different assets, and LCE originating from one set of assets cross-subsidising the costs on other assets relative to the efficient outcome.

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

8.7 This option addresses the problem identified in option 1, by crediting LCE originating from particular connection assets to the participants that pay connection charges for those connection assets. Those participants would be credited LCE for each asset according to rental guides (see Appendix A).

8.8 The remainder of the LCE would be credited in bulk against the remainder of the MAR. Option 2 is illustrated in Figure 7 below.

Figure 7 Option 2: Credit LCE to individual connection assets and credit remaining LCE against the remainder of the MAR



Source: Electricity Authority

8.9 This approach avoids the need for estimating asset and class allocations after LCE is credited against charges for particular connection assets, and largely eliminates the possibility of distortion, gaming or blunting of short term spot signals.

8.10 This option reflects the fact that there is very limited opportunity for gaming of LCE payments or blunting of short term spot market signals in the case of connection assets, as in most cases these assets are used only by a single party. As a result, an attempt to game the charge by offering inefficiently will often result in, at best, a zero net gain. For example if a generator deliberately puts a connection asset into constraint to increase the LCE on it, this will simultaneously reduce the price they receive for their generation, which is likely to reduce their overall profits. This means the possibility of a party having inefficient incentives to game the LCE allocation to offset their transmission charge is largely eliminated.

8.11 Further, because LCE originating from a particular connection asset is used to fund the costs of that asset it avoids LCE from individual connection assets cross-subsidising the costs of other assets and vice versa, which would be inefficient.

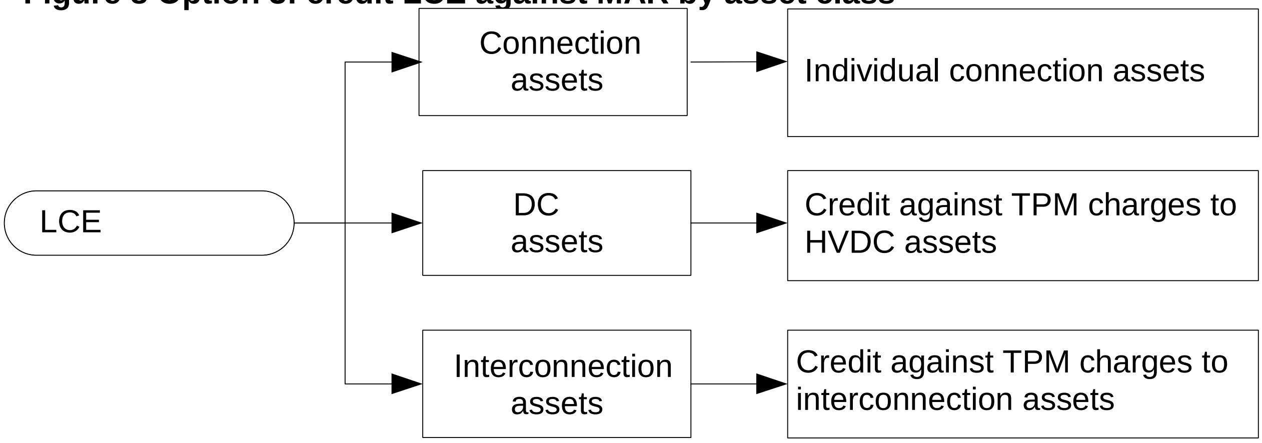
8.12 A further advantage of option 2 is that it preserves the possibility of a simple transition to a more market-based transmission charging regime in the future, if required. In particular, this option preserves the possibility of allocating LCE to a merchant transmission investor in relation to an asset developed by the transmission investor or to a capacity rights holder in relation to an asset subject to capacity rights, should this option become efficient in the future, and provided such assets are treated as connection assets.

Option 3: Apply LCE originating from connection assets against charges for individual connection assets, credit LCE arising from other asset classes by asset class.

8.13 This option credits LCE against the MAR by asset class, except in relation to connection assets where LCE originating from particular connection assets is credited against charges paid in relation to those assets. The rationale for the option is to avoid using LCE originating from one asset class to cross-subsidise the costs of other asset classes.

8.14 This option is the closest to Transpower's current methodology for allocating LCE, except in relation to connection assets. Broadly, crediting LCE against transmission charges for an asset class has the same effect as Transpower's current approach of allocating the LCE by asset class and then rebating LCE customers in proportion to customers' transmission charges in that asset class.

Figure 8 Option 3: credit LCE against MAR by asset class



Source: Electricity Authority

8.15 If there was a high amount of LCE originating from the HVDC link, LCE would offset the revenue that other charges would need to recover in relation to the HVDC, which may be an efficient outcome if there were no risk of gaming or blunting of spot market signals.

8.16 However, unlike connection assets, crediting LCE against charges for the DC assets may be subject to the risks of gaming, or lead to the blunting of spot market signals. This is because constraints and price differences on these assets that result in LCE can impose costs on multiple parties and the benefits can be received by different parties. This means gaming, or blunting of signals, can result in wealth transfers between parties which may be inefficient.

8.17 Similar concerns are likely to arise in the case of interconnection assets.

8.18 The Authority's assessment is that the risks of gaming under this option are likely to outweigh any efficiency benefits from this option of avoiding cross-subsidies between asset classes.

8.19 Another issue with this option is that it is unlikely to be appropriate to allocate LCE separately to DC assets if the TPM was changed so that these assets were no longer differentiated from AC assets for transmission charging purposes.

Assessment

8.20 Table 3 lists the four options and assesses each under the qualitative criteria:

(a) allocation method

(b) accuracy of allocation once residual LCE is taken into account

(c) distortion to costs to be recovered for transmission assets

(d) muting of short-term price signals

(e) potential for gaming.

8.21 The Authority considers that criteria (d) and (e) have the greatest potential impact on achievement of the Authority's statutory objective.

8.22 The more precisely LCE is allocated to individual assets, the greater the potential for nodal price signals to be undermined, and the greater the potential for gaming to occur.

8.23 However, in the case of connection assets, the value of nodal signals and the potential for gaming are greatly diminished, hence the allocation approach for these assets should focus on minimising distortion. Further, this approach avoids LCE originating from particular connection assets being used to cross-subsidise the costs of other assets.

8.24 Based on the results of the assessment in Table 4, the Authority's preferred approach is option 2, which is to:

(a) apply LCE originating from particular connection assets against connection charges for those connection assets

(b) credit the remaining LCE against the remainder of the MAR in bulk.

8.25 As identified in paragraph 7.16, using a long averaging period to calculate the distribution of LCE to assets or asset classes also goes some way to diminishing the identified risks. However, this approach is equally applicable to all four options, although option 2 is still the preferred approach.

Legal implications of alternative approaches

8.26 The Authority notes that the purpose of the TPM is to allocate the full economic costs of Transpower's services (see clause 12.78 of the Code), subject to Part 4 of the Commerce Act 1986. Under Part 4 of the Commerce Act 1986, the Commerce Commission sets the MAR that Transpower may recover from consumers. The TPM allocates the MAR, recoverable costs and pass through costs, which together make up Transpower's full economic costs.

8.27 The Commerce Commission sets the MAR. The Electricity Authority cannot, in the Code, amend the MAR. However, the Authority could (for example) specify that the MAR will be recovered first by payment of the LCE to Transpower (with a methodology for crediting shares of the LCE by customer) and, second, recovered from customers according to a methodology specified in the TPM. Implementing the approach in the example above could involve amendments to the TPM and/or other parts of the Code.

8.28 The Authority will consider the preferred approach to give legal effect to the Authority's intended allocation of LCE to offset transmission charges as part of the second issues paper.

Table 3 Four options for an approach to allocating LCE and a qualitative assessment

Option	Allocation method	Accuracy of allocating LCE	Distortion to costs to be recovered for transmission assets	Muting of Short term price signals	Potential for gaming
Original proposal: credit LCE against individual assets	Rental guides	Some inaccuracies with identifying LCE originating from specific assets.	Possible	Possible	May create new situations where generator/retailer has a competitive advantage
Option 1: Bulk credit of LCE against MAR	None required	No accuracy required	Possible cross-subsidy between assets and asset classes	None attributable to methodology	None
Option 2: Apply LCE originating from connection assets against charges for individual connection assets, credit remaining LCE against remainder of the MAR in bulk	Rental guides for connection	Not affected where connection assets not at nodes in FTR market	Avoids cross-subsidies between connection assets and between connection and other assets	None attributable to methodology	No new gaming potential unless the FTR market is expanded to include FTRs across connection assets
Option 3: Apply LCE from connection assets against individual connection assets, credit LCE arising from other asset classes against MAR by asset class.	Rental guides	Inaccuracies identifying LCE originating from asset classes	Avoids cross subsidies between asset classes but not within asset classes	Very limited if any	LCE likely to be factored into offer strategy across the HVDC. Reduced risk of gaming for non-HVDC (interconnection) assets

Source: Electricity Authority

9 Conclusions and recommendations

9.1 Submissions on the application of LCE as proposed in the October issues paper postulated that nodal price signals will be weakened compared to current arrangements.

9.2 A major change under the TPM proposed in the October issues paper was the introduction of the beneficiaries-pay charge under which participants that benefit from assets pay charges in proportion to that benefit.

9.3 Nodal price signals are efficient but not perfect. The likelihood and degree to which the originally proposed methodology would dull nodal price signals is not clear. However, the possibility that nodal price signals would be materially muted under the proposal cannot be ruled out, particularly in relation to assets subject to charges that vary with spot market outcomes, such as the SPD charge.

9.4 Participants would have the incentive and the ability to alter their wholesale market offer behaviour in response to the TPM proposed in the October issues paper. There is also a possibility that the proposed methodology for allocating LCE would encourage generator/retailers to attempt to “game” the LCE component of the charge to reduce their overall transmission charges and increase their overall profits, while increasing costs to others.

9.5 Given these two risks, and regardless of the actual probability or consequence, a reasonable hypothesis is that the original proposal may not be the optimum solution, in that other options may minimise these risks without compromising on other aspects.

9.6 Alternative options examined in this paper address the two key risks raised by submitters and therefore better promote efficient outcomes than the original proposal. Hence there is a case for proposing an altered approach.

9.7 The Authority’s preferred alternative approach is option 2, which is to apply LCE originating from particular connection assets against connection charges for those connection assets and credit the remaining LCE against the remainder of the MAR in bulk.

9.8 A further modification to the original proposal, which could be applied regardless of the preferred alternative, would be to extend the averaging period for allocating LCE credits to a monthly or annual period. These modifications and implementation considerations, such as how LCE allocation would offset transmission charges in practice, will need to be addressed as part of the second issues paper.

Glossary of abbreviations and terms

AC connection assets	Connection assets as defined in Schedule 14.2 of the Code.
AC interconnection assets	Transmission assets that are not DC assets or AC connection assets.
ACT	Electricity Industry Act 2010
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
DC assets	The high voltage direct current link between Benmore and Haywards (HVDC Link).
FNP	Full Nodal Pricing.
FTR	Financial transmission right – an instrument to mitigate locational price risk. FTRs are awarded by reference to two nodes or groups of nodes (known as hubs).
LCE	The difference between purchaser and generator payments as defined in clause 14.73(2) of the Code.
MAR	Maximum allowable revenue.
MW	Megawatt
Rental	The price differential on a transmission circuit multiplied by flow on the circuit in a given period.
Residual LCE	The amount remaining in the FTR account in a billing period that is not required to settle FTRs.
SPD charge	A beneficiaries-pay based charge (SPD charge) applied to specified transmission assets.
TPM	Transmission pricing methodology.

Appendix A Historical values of LCE

A.1 Transpower currently allocates LCE to customers that pay for assets in any of three classes: AC connection assets, AC interconnection assets, and DC assets. Transpower does this by classifying each transmission arc into one of the three asset classes. The electricity flow across each arc is then multiplied by the price difference across the arc. These values are then summed, with the total price differential for each for each asset class known as the monthly "rental guide".[32]

A.2 These guides determine the proportions in which LCE is allocated to the three asset classes. The LCE can be greater or less than the sum of the monthly rental guides depending on factors such as wash-ups. Once the LCE received by Transpower is allocated to the three asset classes, the LCE is rebated to transmission customers, broadly speaking, in proportion to customers' transmission charges in that asset class.[33]

A.3 Table 4 below provides historical information on the total LCE amounts by calendar year[34] and a breakdown of the asset classes.

Table 4 Historical LCE payments to asset classes

Calendar Year	Connection	HVDC	Interconnection	Total
2000	$ 241,886	$ 9,368,743	$ 72,310,211	$ 81,920,840
2001	$ 5,098,769	$ 7,011,741	$ 99,057,022	$ 111,167,533
2002	$ 772,405	$ 19,938,368	$ 38,950,513	$ 59,661,287
2003	$ 4,025,391	$ 11,300,190	$ 69,429,610	$ 84,755,192
2004	$ 1,742,495	$ 20,333,874	$ 33,532,220	$ 55,608,589
2005	-$ 1,197,262	$ 7,738,124	$ 66,543,568	$ 73,084,430
2006	$ 1,216,613	$ 4,880,973	$ 67,316,671	$ 73,414,256
2007	$ 341,772	$ 4,675,828	$ 36,876,977	$ 41,894,577
2008	$ 6,188,457	$ 49,368,068	$ 134,792,755	$ 190,349,281
2009	$ 4,192,401	$ 65,720,374	$ 28,694,917	$ 98,607,691
2010	$ 6,548,044	$ 18,674,875	$ 42,030,307	$ 67,253,226
2011	$ 7,693,845	$ 32,099,396	$ 62,919,841	$ 102,713,082
2012	$ 6,975,161	$ 39,321,436	$ 66,447,081	$ 112,743,678
2013	$ 3,361,092	$ 14,042,874	$ 29,296,746	$ 46,700,711

Source: Transpower

Note: 1. 2013 only includes the first 8 months of data

2. Years highlighted in yellow indicate dry years

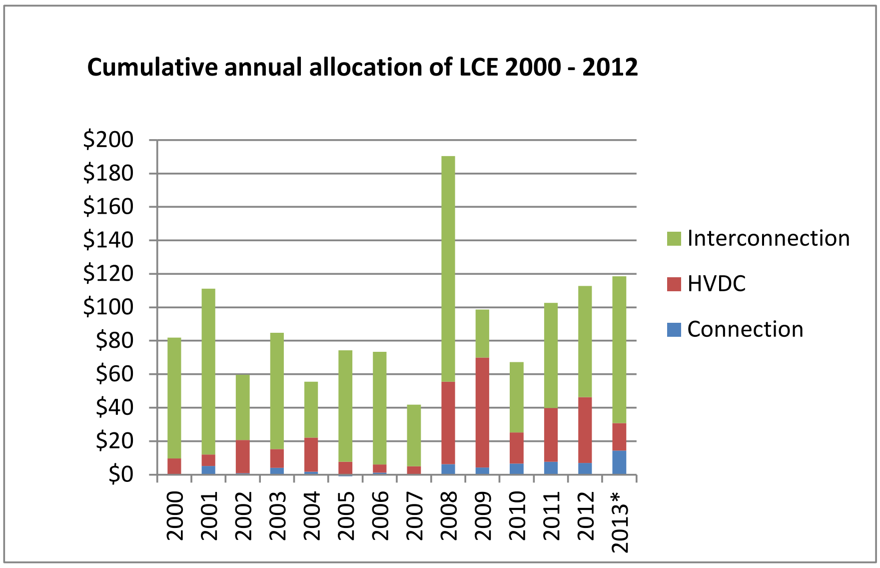
A.4 Figure 9 and Figure 10 plot the values from Table 4. These charts illustrate the variability of the LCE sums to be allocated and the variability of the three assets classes relative to each other.

32 October issues paper paragraph 5.3.3.

33 ibid paragraph 5.3.4.

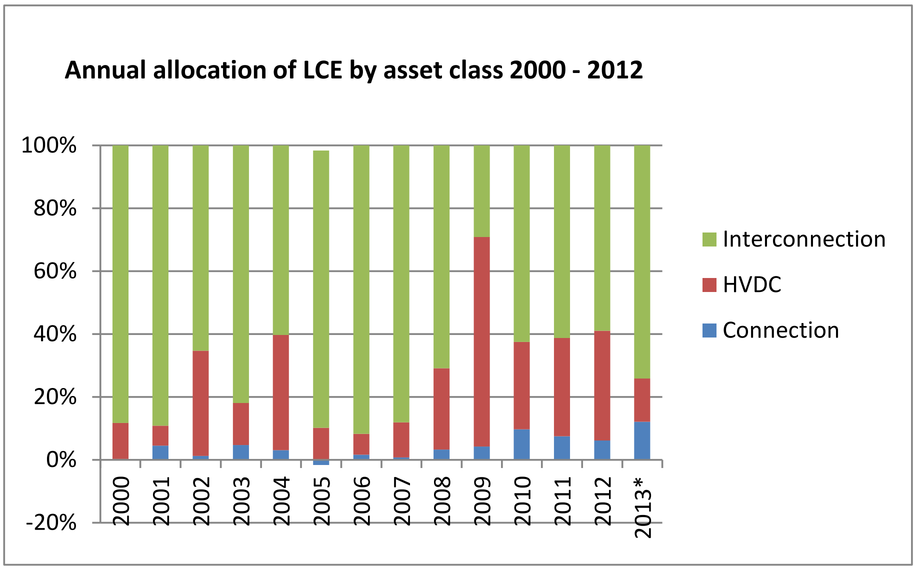
34 See Transpower website https://www.transpower.co.nz/about-us/industry-information/transmission-pricing-methodology-development-2012-electricity#lce-data

Figure 9 Cumulative annual LCE 2000 - 2013



Source: Electricity Authority

Figure 10 Proportions of annual LCE by asset class 2000 - 2013



Source: Electricity Authority

Forecasting LCE amounts

A.5 The FTR market is in its infancy so it is too early to form a view on long-term bidding behavior in the New Zealand FTR market. Consequently, the amount of residual LCE likely to accumulate in the FTR account is unclear. In order to ensure the success of the FTR market and improve the likelihood of revenue adequacy being achieved at each settlement, the Code makes LCE and auction revenue available for settlement of FTRs.[35]

A.6 For nodes at which no FTRs are available, LCE amounts are difficult to forecast. However, it is possible to draw some conclusions regarding future LCE amounts.

A.7 Residual LCE is the amount remaining in the FTR account for a billing period that is not required to settle FTRs.

A.8 The greater the transmission capacity, the lower the amount of LCE. Where transmission capacity is expanded (for example, as has been the case with the commissioning of Pole 3 on the HVDC link), the expected amount of LCE is lower than would have been the case historically in similar market circumstances, because losses are expected to be lower and constraints are expected to be less frequent.

A.9 If capacity on the FTR grid is increased (for example, in relation to Pole 3 of the HVDC link), offer behaviour will also change. This may lead to a change in the amount of LCE.

A.10 If purchasers pay fair value for the FTRs, then, in the long-term, auction revenue is likely to equal LCE that would have been generated on the FTR grid if there was no FTR regime. In theory, FTR buyers will pay more than fair value for FTRs to take into account their value in managing risk. In reality buyers tend to pay less than fair value for FTRs.

A.11 The FTR allocation plan states that the objective is for the FTR account to be revenue inadequate one month in twelve. That means that, under the objective, there will be no residual LCE one month a year.

A.12 As the FTR market expands, more and more LCE will be diverted to the FTR account

A.13 Despite the introduction of FTRs, the amount of LCE paid to transmission customers is still likely to be volatile due to the allocation and FTR processes. This means there is only a loose correlation between LCE and spot market outcomes.

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35 In most FTR market parties compete in Auctions to obtain FTRs, parties most exposed to locational price risks are expected to win the auctions and the proceeds from the auction are distributed in the same way that rentals are otherwise distributed.