ELECTRICITY AUTHORITY
TE MANA HIKO

Settlement Residual Allocation Methodology

Consultation paper

Submissions close: 5pm **27 September 2022**

16 August 2022

Executive summary

Earlier this year the Authority published a consultation paper that proposed principles to guide the development of a new settlement residual allocation methodology" (SRAM) and set out our early thinking on options to be considered.[1] Having considered submissions on the earlier paper,[2] we are now proposing a new SRAM, prescribed in the Code, to replace the current method.

The wholesale electricity market generates a surplus, called loss and constraint excess (LCE),[3] as consumers pay more for electricity than generators receive. Some LCE is used in the financial transmission rights (FTR) market. The balance of funds (the remainder of the LCE and FTR auction revenue after FTR payments have been made) is paid to Transpower, which distributes it to transmission customers. In this paper we adopt the following terminology:

- "settlement residue":[4] the balance of funds received by Transpower
- "settlement residual allocation methodology" (SRAM): the method used to allocate those funds amongst transmission customers
- "settlement residual rebate":[5] the payment received by a transmission customer.

Settlement residual rebates are currently distributed to transmission customers according to an allocation method developed by Transpower. That method depends on charges defined in the current transmission pricing methodology (TPM) and so becomes obsolete from April 2023 when Transpower implements a new TPM.

The SRAM, together with the new TPM, is an important part of the package of pricing signals for access to and use of the transmission grid. Implementing a new SRAM will be an important step, complementary to the Authority's reform of transmission charging. Completing this part of the overall pricing package will improve certainty for investment in new renewable generation, and support achievement of New Zealand's commitment to achieve net zero emissions by 2050. Better pricing signals will help to ensure the best use of existing and future infrastructure and better position New Zealand to make an efficient transition to a low-emissions economy.

The Authority has developed a proposed new SRAM that would allocate settlement residue relating to each of the regions defined for the TPM's benefit-based charge (BBC) simple method using the applicable regional allocators already developed for the TPM.

The Authority considers that its proposed SRAM will lead to significant long-term benefits for consumers. It will encourage more efficient use of the grid, and support the right investments being made at the right time and in the right places. It will, over time, lead to relatively lower prices to consumers for delivered electricity.

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1 *Settlement Residual Allocation Methodology principles, options and pass-through,* 18 January 2022. Available at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/settlement-residual-allocation-methodology-sram/

2 The Authority received 17 submissions and eight cross-submissions in response to the earlier paper.

3 LCE is otherwise known as transmission rentals, monthly settlement or congestion revenue.

4 Also known as "rentals received".

5 The rebate is also known as an "LCE payment".

We are also consulting on an alternative that allocates SRAM in proportion to transmission charges. This option is even simpler than the preferred option. On the other hand, it appears likely to cut across investment signals promoted by the new TPM and does not match rebates to parties who bear nodal transport costs.

Finally, the efficacy of the SRAM is impacted by whether and how distributors pass rebates through to the parties who bear nodal transport costs. Practices vary across the sector, so the Authority is now proposing to introduce pass-through and reporting obligations, in parallel with the proposed new SRAM.

Relationship with other workstreams

The SRAM consultation is closely linked to two other Authority workstreams.

First, as noted above, it is closely linked to the implementation and operation of the new TPM. The SRAM will affect how some benefit-based charge (BBC) allocations are determined, and it influences the incentives for efficient grid use and investment that the TPM is intended to achieve.

Second, it is linked to work on the FTR market because FTR market settings affect how much nodal transport revenue is available as settlement residue and SRAM settings may influence demand for FTRs.[6]

Next steps

Following consideration of submissions, the Authority will decide whether to make a Code amendment to implement a new SRAM and ensure pass-through of settlement residual rebates by distributors. If the Authority decides to incorporate SRAM provisions into the Code, Transpower would be required to apply the new methodology to settlement residue it receives from May 2023 (ie, relating to April 2023 trading).

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6 The Authority is reviewing the wider policy settings for the FTR market and the use of LCE that supports it. The Authority has released an Issues paper on this subject which is available at https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c19182. While changes to the FTR market could alter the amount of settlement residue available to be allocated, the SRAM would not necessarily need to be reconsidered since it simply allocates whatever settlement residue is available.

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1 Introduction

Making a submission

1.1 Please see Appendix E for details on how and by when you can make a submission on this proposal. Appendix G collates all the consultation questions set out in this document. Submissions are due by **5pm, 27 September 2022**.

1.2 Please direct any further questions related to this consultation by email to network.pricing@ea.govt.nz.

Supporting information

1.3 The following table provides links to key information that may be helpful to stakeholders in their consideration of this consultation paper.

Table 1 Key sources of information relevant to this proposal

ITEM	REFERENCE
Transpower's explanation of its loss and constraint excess payment method, 2017	https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Loss%20and%20Constraint%20Excess%20Booklet.pdf
The Authority's 2019 TPM issues paper	https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf
Transpower's TPM development website	https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm
The Authority's consultation paper on the proposed new TPM – September 2021	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c18989
The Authority's consultation on SRAM principles, options and pass-through – January 2022	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/settlement-residual-allocation-methodology-sram/consultation/#c19111
The Authority's decision on the new TPM – April 2022	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/final-tpm-decision/
The Authority's consultation on its observations about the market for FTRs – May 2022	https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c19182

1.4 In the remainder of this paper we discuss:

(a) how settlement residue is currently rebated and why this needs to change

(b) SRAM principles

(c) SRAM options the Authority has considered and its preferred option

(d) options for distributor pass-through of settlement residual rebates that the Authority has considered and its preferred option

(e) the Regulatory Statement for the proposed Code amendment.

2 Background and problem definition

The need for a new SRAM

2.1 The wholesale electricity market produces surplus funds. The market is settled each month using half-hourly prices that vary by node. The price at each node includes an energy component and one or more transport charge components relating to parts of the grid "used" by that node.[7] Nodal transport charges (the difference in nodal prices between market nodes) increase the amount paid by load and decrease the amount paid to generators and so in aggregate produce a surplus – the loss and constraint excess (LCE).[8]

2.2 Most (but not all) of the LCE is currently used to fund the financial transmission rights (FTR) market, which collects FTR auction revenue and uses LCE to support FTR payments.[9] The balance of LCE and FTR auction proceeds after FTR payments have been made (which we call the settlement residue) is transferred to Transpower for distribution to transmission customers.[10, 11]

2.3 There is no requirement in the Code for settlement residue to be distributed to market participants. However, if Transpower retained these funds then it would over-recover its costs, ie, customer payments in aggregate for use of and access to the grid would exceed Transpower's transmission network costs. So Transpower currently distributes the settlement residue amongst its customers. The term used for such a payment in this paper is a settlement residual rebate.

2.4 The current SRAM was developed by Transpower and is detailed in its 2017 rentals guide.[12] Transpower's current approach to the allocation of settlement residue is built on the current transmission pricing methodology (TPM). In particular, it involves:

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7 Transport charge contributions are small (or even negative) for lightly loaded parts of the grid, higher for heavily loaded parts and highest for constrained parts.

8 Transpower's website (https://www.transpower.co.nz/industry/revenue-and-pricing/pricing#Key%20Terms) explains this as follows: *Nodal pricing is used to calculate wholesale electricity prices based on marginal costs at injection and off-take points. Surpluses arise because:*

- *losses are priced at the marginal loss rate while loss quantities are determined by the average loss rate (which is lower than the marginal rate)*
- *when a constraint occurs, consumers pay for all the energy consumed at nodes "downstream" of the constraint at the (higher) marginal prices set at those nodes, but some of the energy consumed at the "downstream" nodes is generated at "upstream" nodes where the prices are lower, and generators injecting at those nodes receive those lower prices.*

9 For information on the flow of funds, including into and out of the FTR market, see Appendix A.

10 As Appendix A, shows, the share of LCE being used to fund the FTR market is significant and has been increasing. The Authority's *consultation on its observations about the market for FTRs* referenced above is considering stakeholder views on this and other FTR-related matters.

11 Clause 14.16(7) of the Code requires the clearing manager to return these funds to the grid owner. The clearing manager is responsible for ensuring that industry participants pay or are paid the correct amount for the electricity they generated or consumed and for market-related costs. NZX is contracted to the Electricity Authority to provide the clearing manager market services.

12 Transmission rentals guide (loss and constraints excess booklet)

(a) treating settlement residue as if it is LCE, and using a single scaling factor to adjust for the difference between total modelled LCE and total settlement residue each month[13]

(b) mapping settlement residue to each connection asset (individually), the interconnection assets (collectively), and the high voltage direct current (HVDC) link

(c) allocating the settlement residue related to each connection asset to its associated customer(s)

(d) allocating the interconnection portion of the settlement residue to offtake customers in proportion to their contribution to interconnection charges[14]

(e) allocating the HVDC portion of the settlement residue to South Island generators in proportion to their contribution to HVDC charges.

2.5 Due to its reliance on the current TPM, Transpower's current allocation approach will become obsolete once the new TPM is in place. This is the immediate reason why the Authority is considering a new SRAM, ie, the basic problem.

2.6 Further, the way the settlement residue is allocated has implications for the Authority's statutory objective. Together, the new TPM and SRAM have important effects on incentives for both use of the grid and investment in transmission and generation assets. A well-designed SRAM, over time, will lead to relatively lower prices for delivered electricity. A poorly designed SRAM could lead to unnecessary additional cost and relatively higher electricity prices for consumers. Getting these settings right is increasingly important, given the significant investments that will be required to serve the rapidly increasing demand for electricity.

2.7 For these reasons, the Authority proposes to amend the Code to ensure the appropriate allocation of settlement residue.

2.8 Specifying the SRAM is necessary but not sufficient to ensure that all end-users are not being over-charged for transmission services. Although most distributors pass on any settlement residual rebate they receive to their customers, there is no requirement on them to do so, and it appears some do not. We therefore also explore options for how distributors treat any settlement residual rebate they receive.

The SRAM must be consistent with the Authority's statutory objective

2.9 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.[15]

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13 This treatment is consistent with clause 14.35 of the Code, which requires grid owners to treat residual loss and constraint excess as loss and constraint excess.

14 The interconnection charge is also known as the Regional Coincident Peak Demand (RCPD) charge.

15 Parliament is currently considering an amendment to the Authority's statutory objective to add an additional objective, being to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers. The explanatory notes of the introduction version of the Bill states:

> "The additional objective is not intended to affect the Authority's functions relating to how industry participants deal with other industry participants (eg, trading conduct and information exchange),

2.10 Nodal prices in the wholesale market are designed to promote efficient use of the grid, and the TPM is designed to recover Transpower's recoverable revenue in ways that support efficient investment in the grid. However, together they recover more than Transpower's costs of providing transmission services.

2.11 LCE has ranged from 6% to 18% of transmission charges in recent years. The FTR market has consumed some LCE[16], leaving a settlement residue of 5% to 10% of transmission charges. This is a material sum overall, and LCE is highest at times and locations where transmission links are stressed – ie, when usage and investment signals are especially important. As the settlement residue is a substantial sum, the SRAM can have a significant impact on grid usage and investment signals.

2.12 The TPM, the SRAM and nodal prices work together as a package for pricing the access to and use of the transmission grid. A well-designed SRAM should return the over-recovery to grid users without undermining the incentives provided by wholesale electricity prices and the TPM for efficient grid use and investment. This would promote the Authority's statutory objective.

2.13 To support efficient grid use, a party's rebate should not be correlated with its use of the grid. If a party's rebate is correlated with its use of the grid, this would create incentives for inefficient grid use decisions (essentially by dampening down the nodal price signal).

2.14 To support efficient investment decisions, a party's settlement residual rebate should not undermine the role of the TPM in encouraging users to take future grid upgrade costs into account when making their investment decisions. Future grid upgrade costs are likely to be substantial, given that the demand for electricity is forecast to increase by 50 percent by 2050.

Consultation questions

#Do you have any comments on the problem definition and background material in this chapter?

how prices are determined (eg, wholesale and retail electricity prices), or how costs are allocated between industry participants (eg, costs of transmission and ancillary services)."

The proposals in this Consultation Document relate to the allocation of the costs of transmission between designated transmission customers and the pass-through of those costs to distributors' customers. We therefore consider that, if the amendment proceeds in its current form, it will not affect the proposals outlined in this document. We will reconsider this question if and when an amendment to the Authority's statutory objective is passed into law.

16 FTR payments are funded by using the revenue generated from the auction of FTRs (ie, money paid by participants purchasing FTRs) and, if the FTR auction income does not fully cover FTR payments, then allocated LCE (known as FTR rentals) is used to cover the shortfall. Historically, 30% of payments to FTR holders has come from LCE and 70% from auction revenue.

3 Principles

3.1 Based on these sorts of considerations, the Authority consulted in May 2022 on draft principles that could be used to evaluate SRAM options now and potentially in the future. Most submitters made submissions with respect to these principles.

3.2 Some submitters suggested the principles should be ranked. We consider that it would be inappropriate to rank the principles, as there are trade-offs between them.

3.3 Some submitters queried whether SRAM principles are needed, given:

(a) the Authority's clear statutory objective; and

(b) the Authority's decision-making and economic framework (DMEF).

3.4 We consider that:

(a) the principles usefully translate the statutory objective to the specific issues raised by the SRAM methodology – but they do not override the statutory objective; and

(b) the DMEF was developed to guide TPM development, whereas SRAM engages with both nodal pricing and the TPM (that said, the proposed principles do not conflict with the DMEF).

3.5 Based on feedback received in submissions and further analysis, we have simplified and re-framed the principles. The following table sets out the five principles that we consulted on (right-hand side) and the four principles we are now adopting (left side).

3.6 The change from five principles to four reflects our view that mitigation of volatility is better viewed as an aspect of the over-payment principle.[17]

Table 2 Simplified and reframed principles

Adopted SRAM principles	As previously consulted
Reduce over-payment for transmission	Full cost recovery
	Mitigation of volatility
Do not undermine grid usage signals	Integrity of the nodal transport charge
Do not undermine investment signals	Integrity of TPM benefit-based charge
Do not add disproportionate cost or complexity	Cost and practical considerations

3.7 The SRAM principles are consistent with the Authority's statutory objective, primarily addressing matters relevant to the efficiency limb of the statutory objective.

3.8 We discuss each of the principles further below, together with issues raised in submissions. Appendix B provides an overview of and more detailed responses to

[17] The parties paying the nodal transport charge are the parties over-paying and the parties subject to the nodal transport charge volatility, since they pay both their share of the relevant benefit-based investments and the nodal transport charge. Refunding the settlement residue to them offsets both the over-payment and the volatility.

some significant issues raised in submissions. We then go on to use the principles in our evaluation of SRAM options.

Reduce over-payment for transmission

3.9 Most submitters supported this principle. However, many incorrectly argue that only load customers pay nodal transport costs, or that generators will simply pass on any costs they face. We disagree with both arguments, for the reasons discussed in Box 1 below.

Box 1: Generators face nodal transport costs too

Grid congestion results in prices that are:

- higher at downstream nodes – this imposes a cost on load at those nodes;
- lower at upstream nodes – this imposes a cost on generators at those nodes.

So, all parties that use a congested part of the grid – either to import energy from distant generators or to supply energy to distant load – face a cost and contribute to LCE.[18] Hence, we disagree that overpayment does not apply to generators.

We also disagree that generators can simply pass on the nodal transport costs. These costs depend on a generator's location. Because generators that are distant from load (or behind a congested part of the grid) compete with local (and embedded) generators, they cannot simply pass through their nodal transport costs.

3.10 The aim is not to perfectly offset nodal transport costs faced by each grid user, because that would undermine grid usage and investment signals. Rather, our view is that rebates should *broadly* be allocated to the generators and load who face nodal transport costs – provided that can be achieved without undermining usage and investment signals.

3.11 Nodal transport charges are volatile, so allocating residue to the parties who bear that cost may provide a further benefit of reducing the cost to those parties of managing locational price risk.

3.12 Several submitters argued that reducing volatility and preserving nodal price integrity are incompatible objectives. We disagree, for the reasons set out in Box 2 below.

Do not undermine grid usage signals

3.13 A number of submitters supported this principle. Nodal prices coordinate supply and demand by signalling the marginal cost of energy and the marginal cost of transport – ie, the cost of transporting energy to or from a node. These signals play a critical role in the efficient operation of the power system.

3.14 If the rebates are fixed, then nodal price signals are unaffected by the rebate. In contrast, if rebates vary with usage, then users will take that into account and become less responsive to nodal price signals – ie, less likely to reduce demand (or increase generation) at congested locations. This would lead to less efficient grid usage decisions, and so would impose unnecessary costs on grid users.

18 In the case of generators, the 'cost' to them is lower revenues.

Box 2: SRAM can mitigate locational price risk and preserve nodal price signals

When nodal prices downstream from a congested part of the grid are elevated, that signals that it is costly to supply more demand. For example, a price of $500 per MWh means:

- adding 1 MWh of demand will cost $500;
- reducing demand by 1 MWh will save $500;
- generating 1 MWh will earn additional revenue of $500.

Consider a consumer located at the node who receives an LCE rebate that is *fixed* (the consumer's rebate allocation is the same, regardless of how much energy they consume).

Receiving an LCE rebate means the consumer does not suffer as much from congestion, so the risk associated with unpredictable congestion (and volatile nodal transport costs) is reduced.

However, the consumer's marginal cost or saving is not affected by a fixed rebate – changing their usage by 1 MWh will still change their costs (or revenue) by $500. This means the nodal price *signal* is preserved.

This principle is familiar from experience with FTRs and other hedging products. With all these instruments, it is possible to mitigate locational price risk experienced by a grid user while still preserving the (volatile) marginal price signals faced by that grid user.

Do not undermine investment signals

3.15 As originally formulated, this principle did not garner much support from submitters.[19] We have reframed the principle to make it clearer.

3.16 Most submitters seem to assume that allocation of settlement residual rebates is unrelated to the TPM and can be considered independently. However, this is not the case.

3.17 Grid investments typically reduce congestion on a transmission link. This reduces the amount of LCE produced by that link, and thereby reduces the value of rebates received by transmission customers.

3.18 So, the benefits received by a transmission customer from any given grid investment depends on their exposure to congestion *and* their entitlement to rebates. This means the allocation of benefit-based charges for (at least some) grid investments must consider:

(a) the benefit of reduced congestion (and hence nodal prices with a smaller transport component), and

(b) the reduction in rebates received.

3.19 The change in the amount of rebates a grid user can expect to receive inherently modifies the benefit that the user stands to gain from a grid investment – so there is

19 The original wording was: "Integrity of TPM benefit-based charge".

an unavoidable interaction between the rules for allocation of settlement residual rebates and the allocation of benefit-based charges for grid investments.

3.20 Specifically, the TPM works by allocating the benefit-based charge for an investment in proportion to the private benefits each transmission customer is expected to get from that investment. This means that, ideally, the LCE generated by an investment should be returned to the parties that were assessed as benefiting from the investment in the same proportions.[20] Otherwise a disconnect will be created between the benefits provided by a transmission investment (leaving aside rebates) and the dis-benefit caused by loss of rebates associated with that investment.

3.21 For this reason, a poorly designed SRAM can lead to a poor allocation of benefit-based charges – potentially resulting in inefficient investment incentives for transmission customers. The new TPM is designed to ensure generation investors take grid costs into account when deciding on the location and design of new generation. A poorly designed SRAM that overly reduces a user's exposure to grid costs (or overly exposes it) can undermine this objective. This is discussed further below, in the consideration of SRAM options.

Principles adopted for evaluation

3.22 We use the refined principles to evaluate SRAM options below and expect they would be useful if we were to revisit the SRAM in future.

3.23 In the previous consultation we mentioned the principles could be useful if we were to include operational review provisions for the new SRAM. We now consider that such a mechanism is unnecessary – hence we do not propose to codify the principles. Instead, we would treat any change to the SRAM as a standard Code amendment.

Consultation questions

Do you have comments on our proposed SRAM principles?

Do you have comments on anything else in this chapter?

20 The result is then that the rebate causes the same proportionate adjustment to the benefit that each beneficiary receives from the investment – ie, rebates do not upset the benefit-based charge allocations.

4 SRAM options

4.1 Following the Authority's earlier consultation on SRAM options and our consideration of submissions, we have considered four main options for allocating settlement residual rebates:

(a) 'TPM charges' option: allocate rebates to each transmission customer in proportion to that customer's total transmission charges;[21]

(b) 'Simple BB' option: allocate rebates to parties that use congested parts of the grid, using the regional allocators that Transpower has developed for allocating the costs of low-value benefit-based investments via the benefit-based charge (BBC) simple method in the TPM;[22]

(c) Outside options: transfer surplus LCE outside of the system, for example transfer it to the Crown or use it to fund service providers;

(d) 'Wholesale market' options: allocate rebates to wholesale market purchasers, in proportion to their monthly settlement value or energy volume.

4.2 Below we discuss key insights from our evaluation of these options.

The TPM charges option is simple but has mixed results against principles

4.3 The TPM charges option is simpler than the current SRAM (and the Simple BB option), though it does retain the administrative costs of rebating via network businesses. In our view (and noting the significant learning curve the new TPM has for participants) simplicity should not be undervalued provided it does not lead to other significant negative consequences.

4.4 The TPM charges option also does not undermine grid usage signals in the way that wholesale market options do (as discussed below). This is because rebates would be allocated based on largely fixed proportions that do not depend on usage.

4.5 Our primary concern with this method is that it would to some extent undermine the investment signalling benefits of the TPM benefit-based charges. At the margin, it may adversely influence participant choices. It may also tend to present large TPM customers with lower costs of expansion compared to small customers. While these are not necessarily fatal flaws, it is desirable to avoid them if this can be achieved without significant cost or complexity.

4.6 To explain, the benefit-based charge in the new TPM is designed to ensure grid users take future grid upgrade costs into account. Over time, this should ensure more efficient coordination of investment in generation, load and the grid. For example, exposure to costs of future grid upgrades (via BBC allocations) should influence:

(a) a generation investor deciding where to locate new generation capacity, how much capacity to build, whether to invest in on-site flexibility and how to profile output;

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21 We also considered variations on this option that use only benefit-based charges, or only residual charges. However, the residual charges-only variation performs less well because it does not address generator over-payment. The BBC-only variation performs similarly to the total TPM charges option.

22 We also considered a Full BB option that uses bespoke allocators where available – but this option has been dropped on the basis it is too complicated and adds little value compared to the Simple BB option.

(b) a load party deciding where to locate, whether to electrify or how much flexibility or on-site generation to provide; and

(c) a distributor deciding where or how to tie into the grid, how much to invest in flexibility or how strongly to signal the value of flexibility through their own pricing.

4.7 If those parties take account of the cost of any grid upgrade in their own decision-making, then that will lead to lower overall system costs over time.

4.8 It would detract from this objective if rebates were allocated to parties in proportion to their transmission charges. A customer who pays high transmission charges would have less exposure to nodal transport charges (due to its high rebate) and should also be allocated a lower share of future upgrade costs.[23] This means that such large customers have an inefficient incentive to undervalue their impact on grid investment (and vice versa for small customers). This would, for example bias:

(a) small customers toward local or embedded generation, and large customers toward remote generation;

(b) small customers toward over-investment in flexibility, and large customers toward under-investment; and

(c) small load customers against electrification.

4.9 This option also performs poorly in terms of addressing over-payment. While it does address over-payment in aggregate, it does not broadly allocate rebates to the parties who have overpaid – that is the parties exposed to nodal transport charges. Rather, the TPM charges option rebates to the same parties every month, regardless of where congestion occurred (and therefore who bore the cost and risk of nodal transport charges). This means every month there would be transfers from parties who bore nodal transport charges to parties who did not.[24]

4.10 Despite its poorer performance against some of the SRAM principles, this option performs well in terms of cost and complexity. We are therefore open to the view that this might outweigh its disadvantages. We seek submissions on this point.

The Simple BB option is the most balanced option

4.11 The Simple BB option performs well in terms of reducing over-payment for transmission. It allocates LCE to parties using congested parts of the grid (ie, the parties who are exposed to nodal transport charges). The allocation is fixed, but broadly addresses over-payment for load and generation. Because the Simple BB

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23 This depends on which BBC allocation method is used. The TPM requires that a grid investment's effect on rebates is taken into account under the clause 52 standard method for allocation of BBCs (under this method modelled prices are used to allocate between regional groups of beneficiaries, as well as quantities). However, rebates are not taken into account under the simpler clause 51 default method (which allocates on quantities).

24 Further, this option means LCE would be transferred to customers who pay the residual charge and to the assessed beneficiaries of recent (high covered cost) investments – ie, to users *least* likely to be exposed to nodal transport charges. It therefore increases cashflow volatility for all the parties involved, compared to the simple BB option.

option matches rebates to the parts of the grid where congestion occurred each month, it also to some extent mitigates locational price risk for grid users.[25]

4.12 The Simple BB option preserves grid usage signals provided by nodal prices. Simple method allocators are designed to behave like fixed allocations (they are updated only every five years). As they are fixed, they do not undermine nodal price signals.[26]

4.13 The Simple BB option does not frustrate the objectives of the benefit-based charge – any user retains the correct incentive to take its exposure to future grid upgrade costs into account. For example, an investor in generation would have the correct incentive to take into account grid costs in deciding on the location of new generation – as the Authority intended in introducing the new TPM. That's because the Simple BB method uses fixed allocators that reflect each user's historical usage of each part of the grid.[27] Whenever a user expands its usage of a given part of the grid, it will generally be exposed to nodal congestion costs for that part of the grid in proportion to the new usage. So, the user will also be a bigger beneficiary of grid upgrades to relieve the congestion (and pay larger BBCs as a result).[28] This relationship is imperfect,[29] however it is likely to result in better outcomes than the other SRAM options considered in this paper.

4.14 In terms of administrative cost and complexity, the Simple BB method is closest to Transpower's current method for allocating LCE rebates. Transpower already applies an LCE mapping approach to the HVDC and to every connection line and transformer. The Simple BB method retains the current approach for connection assets. It adopts the same mapping approach and applies it to the Simple BB regions. It then adopts the same regional allocators Transpower has already developed for the TPM.

4.15 From a grid user perspective, we expect the Simple BB option will become predictable and readily understandable over time as grid users become more familiar with the TPM. Transmission customers already have an incentive to invest some effort to understand their exposure to each region in terms of the TPM simple method regional allocators – as this will help them to predict their transmission charges. This understanding would translate across to the SRAM if the Simple BB SRAM option is selected – as each customer's eligibility for rebates would be based on the same allocators.

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25 The partial offset against locational price risk provided by the SRAM would become a more important benefit if a greater portion of LCE was returned as settlement residue – either due to FTR market design changes, or changes in FTR market participant behaviour.

26 This point is demonstrated via a simple numerical example in Appendix C. The situation is more nuanced if a user has market power (eg, a generator that can shift the nodal price at its node) – an issue raised by Transpower in its submission. If this is the case, rebates based on simple method allocators may have either a neutral impact on grid usage signals, or a beneficial effect (ie, the user responds more efficiently), depending on the situation. See Appendix D for more on this point.

27 A user's historical level of usage is shielded from nodal transport charges (by its rebate eligibility) while any new usage is exposed.

28 Again, this depends on the BBC methodology Transpower selects.

29 This relationship is imperfect because allocators update periodically, and average across all grid flow conditions, and LCE is pooled within each region.

Outside options cannot address over-payment

4.16 Options where surplus LCE is diverted to some other purpose cannot address the over-payment problem, as these options would mean LCE, which is “paid” by grid users, is not rebated to grid users. For this reason, we have not considered these options further.

Wholesale market options undermine grid usage signals

4.17 In the January consultation paper, we discussed allocating rebates to participants in proportion to the *value* of their energy purchases in the wholesale market. We have dismissed this option because it undermines nodal price signals. Under this option if a purchaser facing a high nodal transport price increases its demand, it will receive a materially larger rebate – and the higher the nodal price, the larger the rebate. This would directly undermine the signal sent by the high nodal transport price (ie, the high benefit to all consumers from a reduction in consumption at that node).

4.18 While many submitters supported this option, this support often appeared to be based on misunderstandings about who bears nodal transport costs and about the influence of rebates on investment signals. Submissions are discussed further at Appendix B.

4.19 Some submitters did recognise the problem of undermining nodal price signals and instead suggested rebates be allocated in proportion to energy purchase *volumes* (ie, GWh instead of dollars). This variation on the original option modifies the problem but does not solve it. The nodal price signal is still undermined to a significant extent, as under this option if a purchaser increases its demand, its rebate will increase proportionately to its increase in demand.

4.20 Both variations also perform poorly against other principles:

(a) the largest purchasers would always receive the largest rebate, even when they are not exposed to congestion costs (and other parties facing congestion would over-pay);

(b) this then leads to the same investment signalling problems as discussed for the TPM charges option;

(c) the options also leave generators fully exposed to over-payment, as they would receive no rebates under these options.

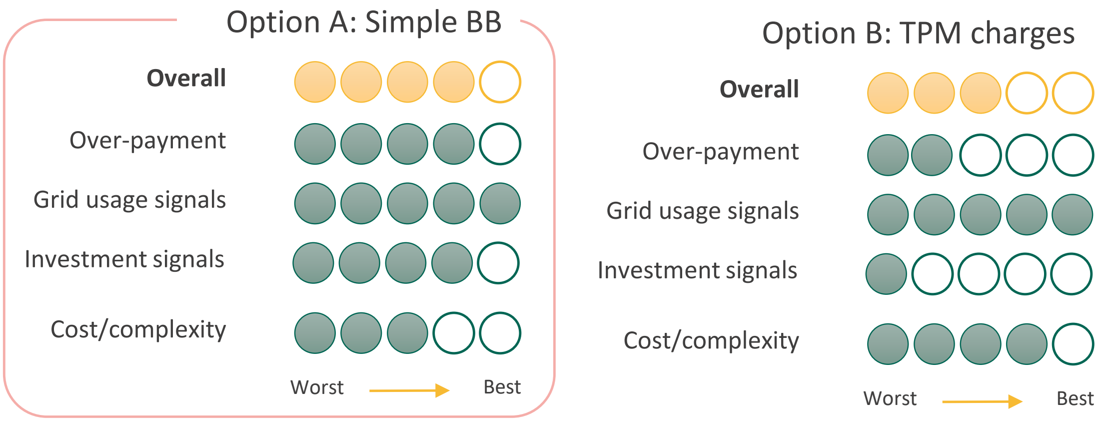
4.21 In terms of administrative cost, the wholesale market methods involve the most significant disruption initially because they would shift rebate obligations from Transpower to the clearing manager. However, the methods then become relatively simple to operate.

4.22 Overall, this option has similar effects to the TPM charges option, except that it also materially undermines nodal prices and leaves generators fully exposed to over-payment.

Summary of options

4.23 The following diagram summarises our evaluation of the Simple BB option and the TPM charges option. The other options discussed above perform materially worse than these options and are not considered further.

Figure 1 Evaluation of SRAM options



4.24 Overall, we prefer the Simple BB approach to the SRAM. However, we are open to the view that the simplicity of the TPM charges approach might make that the preferred option.

Customer impact

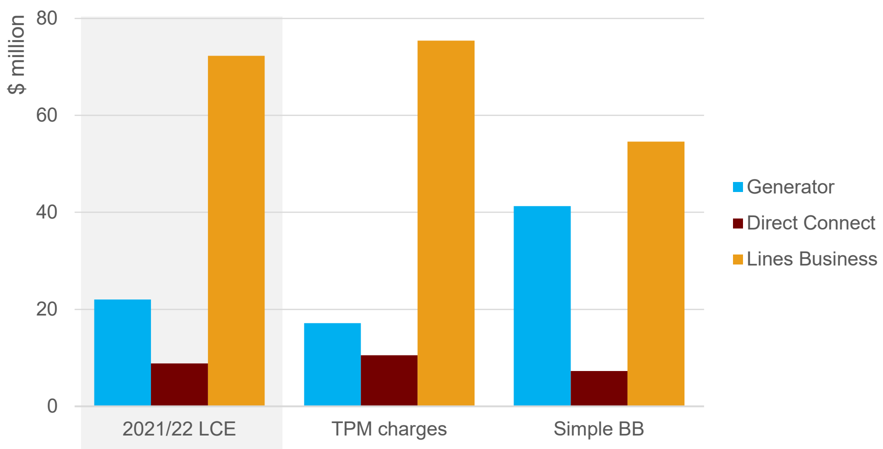
4.25 Settlement residue rebates are part of a system of transmission price signals that also includes transmission charges (set via the TPM) and nodal transport charges.

4.26 Below we compare indicative near-term impacts of SRAM options on a standalone basis, and also illustrate the longer-term impact of the Simple BB option, in combination with the effect of the new TPM, on generators and load.

Illustration of standalone near-term impacts of SRAM options

4.27 To help provide some context, below we set out indicative estimates of the impact of SRAM options on the settlement residual rebates expected to be received by different groupings of transmission customers. The figure below compares, in aggregate, actual rebates received for the year ended March 2022 with estimated rebates under the TPM charges and Simple BB options. Further context is set out at Appendix F (illustrating the combined near-term impact on generators of transmission charge and settlement residual rebate changes under the Simple BB option).

Figure 2 Indicative near-term impact of TPM charges and Simple BB options



4.28 The figure above indicates that:

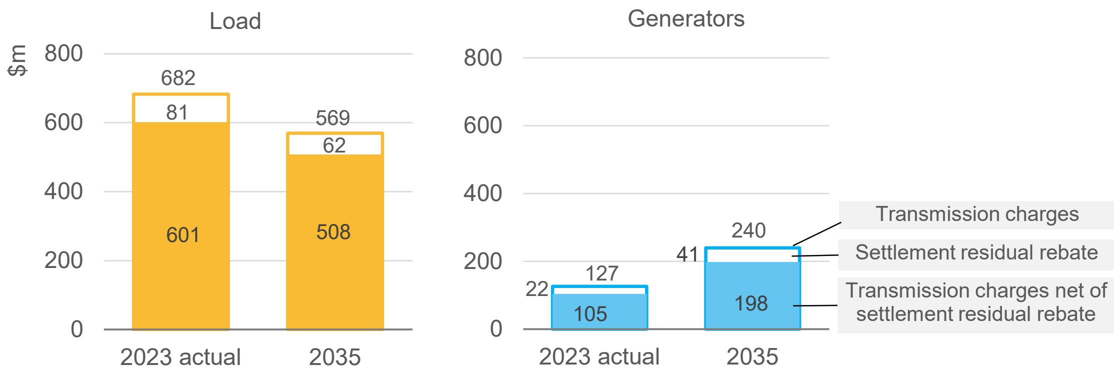
(a) under the TPM charges option, there would be limited immediate impact on the balance between the settlement residual rebate amounts paid to load (in aggregate) and generation (in aggregate)[30]

(b) under the Simple BB option, the share of rebates paid to generators (in aggregate) would be higher, and the share paid to load (in aggregate) would be lower, compared to the status quo.[31]

Longer-term impact

4.29 Over the longer term, the Authority's reforms to the system of transmission price signals (including the new TPM together with the proposed new SRAM) will result in load customers paying lower net charges (that is, transmission charges net of settlement residual rebates) and generators paying higher net charges. The figure below illustrates this using transmission charges projected for 2035.[32] It is appropriate to consider the impact of the proposed SRAM within this broader context (given the interdependencies between the proposed SRAM and the new TPM).

Figure 3 Load customers pay lower net transmission charges in longer-term
(combined impact of Simple BB option and new TPM)



30 Over time, however, generators would receive an increasing share of rebates under the TPM charges option (due to their increasing share of transmission charges) and load customers' share would decrease over time. The TPM charges option would also result in proportionately higher rebates for parties using newer parts of the grid, which are less likely to be congested.

31 Our estimates for the Simple BB option use Transpower's actual rebates for connection assets rather than assessing connection asset congestion directly. We then mapped the settlement residue to benefit-based investments. For the TPM charges option we calculated allocators based on Transpower's indicative charges for 2022/23.

32 The illustration assumes transmission revenues are a constant $809m (as per Transpower's indicative pricing for 2022/23), and that settlement residue is unchanged in terms of overall size and where LCE occurs. The illustration builds on Transpower's transmission charge projection for 2035 that was published alongside the Authority's 2021 proposal for consultation on the proposed TPM. Transpower has explained the assumptions and limitations of its projections, which also apply to the Authority's illustration. Refer Transpower, Pricing year 2022/23 Indicative Prices, 27 April 2022, Chapter 7. www.transpower.co.nz/sites/default/files/uncontrolled_docs/Pricing%20Year%202022-23%20Indicative%20Prices.pdf

4.30 A key difference between the Simple BB option and the TPM charges option over the longer term is how the share of settlement residual rebates will change over time:

(a) under the TPM charges option, generators would receive an increasing share of rebates over time (due to their increasing share of transmission charges) and load customers would get a decreasing share

(b) by comparison, for the Simple BB option, the share of the rebate accruing to generators vs load customers is not expected to change as much over time.

Code amendment

4.31 Appendix H includes proposed drafting to incorporate the Simple BB option into the Code as the new SRAM. It also contains drafting for the TPM charges alternative.

4.32 The drafting introduces an explicit obligation on Transpower as to how it allocates settlement residue but leaves Transpower to develop and publish operational detail regarding its prevailing methodology.[33]

4.33 We have also provided that a party's allocation of settlement residue is a debt recoverable in a Court. This is to ensure parties who are owed rebates can seek redress directly if they are not paid.

4.34 The benchmark agreement, which is incorporated by reference into the Code and which transmission agreements must generally be consistent with, currently includes provisions that deal with the calculation of settlement residue. These provisions require Transpower to calculate settlement residue in accordance with its prevailing methodology.

4.35 We have considered whether any amendment to the Code, including the benchmark agreement, is required to enable the proposals in this paper. In our view no amendment is required as Transpower will be able to comply with the proposed new requirements consistently with the terms in the relevant agreements. Any amendments to make improvements to the benchmark agreement will be progressed separately and at a later time.

Consultation questions

Do you have comments on our preference for the Simple BB approach to the SRAM?

Do you have any comments on our assessment of other SRAM options, including in particular the TPM charges method?

#.Do you wish to propose another option for consideration?

Do you have any comments on the proposed drafting to incorporate the SRAM into the Code?

In particular, do you have any comments on:

- the proposal to make a party's allocation of settlement residue a debt recoverable in a Court?
- the relationship between the Code Amendment, the benchmark agreement and transmission agreements?

Do you have comments on anything else in this chapter?

33 For Transpower's current prevailing methodology, refer to the *Transmission rentals guide*.

5 Distributor pass-through

5.1 Distributors receive a large proportion of total rebates, both currently and in the future under either the Simple BB option or the TPM charges option. Distributors currently vary as to whether and how they pass rebates through to customers, owners, or trust beneficiaries.

5.2 As discussed earlier in this paper, the new SRAM principles seek to both fix a basic problem (ie, that the current allocation is based on the existing TPM, which is to be replaced) and to promote the Authority's statutory objective. A well-designed SRAM, over time, will lead to relatively lower electricity prices for consumers.

5.3 However, as discussed in the January 2022 consultation paper, this can only be achieved if transmission users (generators, industrial consumers, and retailers or their customers) receive the settlement residual rebates. These parties face both network charges and the cost of energy purchases, so transmission charges, rebates and nodal transport charges are united at this level. However, if distributors do not pass on the rebates, some of the benefits of the SRAM discussed above will not be achieved. In particular, if distributors do not pass the settlement residual rebates on to the parties that they are passing on transmission charges to, those parties will be paying more than the cost of providing them with transmission services.

5.4 To best support the potential benefits identified earlier – offsetting congestion costs and not undermining grid use and investment signals – our view is that distributors should pass their rebates through to their retail, direct generation, and direct load customers – ie, the customers with whom they have use of system agreements.[34] Ideally, pass-through would:

(a) use relatively fixed allocators that avoid muting nodal price signals

(b) support investment signals by providing reasonable neutrality between grid-connected vs. distribution-connected end users

(c) be monthly, so that rebate volatility broadly offsets nodal transport charge volatility.

5.5 There was relatively widespread support in submissions on our January 2022 consultation paper for mandating pass-through by distributors.[35] Submitters mostly focussed on the extent to which rebates would reach end users, with some discussion of operating cost and complexity. Submitters did suggest intermediate options of disclosure-only and non-prescriptive pass-through.

5.6 Following this consultation and submissions, we have analysed further four main options for distributors' treatment of settlement residue:

(a) status quo – rebates are unregulated revenue: distributors have full discretion as to whether rebates are passed through, distributed, or retained

34 We consider it sufficient for the rebate to be passed through to retailers, because competition will provide retailers with an incentive to pass the expected value of rebates on to their customers in a way that suits the customers' preferences. This is discussed further below.

35 For example, Contact, Electric-Kiwi, ERANZ, Flick, Genesis, Mercury, Meridian, Nova and Transpower supported pass-through to retailers.

(b) enhanced disclosure – as above, but distributors would be required to disclose their treatment of rebates (ie, their methodology, and the results of its application)

(c) limited pass-through obligation – enhanced disclosure, plus distributors required to pass rebates through to their customers, but with limited prescription as to how or when

(d) full pass-through obligation – as above, but with prescription as to how and when rebates are allocated and passed through.

5.7 The following sections consider each of these four options.

Status quo

5.8 The Authority received a Code change proposal from Mercury in 2019 seeking introduction of a clause that would require distributors to pass rebates through to retailers. The proposal was supported by a report,[36] indicating that:

(a) nearly 20% of settlement residual rebates (by value) may be retained by distributors;

(b) around 50% is passed through to retailers; and

(c) the balance (30%) is either used to reduce transmission charge pass-through on an annual basis or is passed directly to end consumers.

5.9 Similarly, submissions on the January 2022 consultation paper noted that distributors varied in the extent to which they pass on settlement residual rebates.

5.10 Whether or not this is the case, it is clear that distributors are not required to pass on the settlement residual rebate and do not have to disclose what they have done with it. This at the very least provides them with an opportunity not to pass through the rebate.

5.11 Since this could mean that end users collectively may be paying more in total than Transpower's costs for transmission services, this would mean that they may be over-paying for transmission services, which is inconsistent with the principles outlined above. Since the cost of passing on the settlement residual rebates is likely to be modest (and would be saved only by those distributors who chose not to pass through the rebates), we consider there is a strong case for moving away from the status quo.

Enhanced Disclosure

5.12 The least prescriptive way to buttress the incentive for distributors to pass through settlement residual rebates would be to make a Code change to require distributors to disclose what they do with the rebates and, if they are distributed, the method used to determine how they are allocated.

5.13 While disclosure would be likely to enhance the incentive on distributors to pass through settlement rebates, it still gives them the opportunity of retaining some or all of the rebate or distributing it in other ways. It therefore does not ensure that end users are not over-charged for transmission services.

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36 *Loss and constraint rentals - economic analysis of Mercury code change proposal*, Kieran Murray, Dean Yarrall, Sapere Research Group, 26 March 2019.

5.14 Enhanced disclosure would appear to have very little advantage compared to a limited pass-through obligation: if it results in pass-through, it is in practice the same as – and has similar costs to - limited pass-through; and if it does not, it results in over-charging users for transmission services, contrary to the SRAM principles outlined above.

Limited pass-through obligation

5.15 Under this option, distributors would be required to pass through the settlement residual rebate to their customers at least annually.

5.16 According to the Sapere report cited above, many distributors are already passing through the settlement residual rebate to their customers, either directly or as credits against transmission charges. This suggests that the cost of passing on all the settlement residual rebates is likely to be modest. Since this is the minimum obligation that ensures that distributors' customers are not over-charged for transmission services, and it would at most impose additional costs only on those distributors who are not currently passing the settlement residual rebate through, we consider that it is appropriate to mandate at least a limited pass-through obligation.

5.17 We have considered the possibility that distributors should have the option of passing through the settlement residual rebate directly to end users. Several submitters raised this option. For example, Network Tasman stated that it retained the rebate to offset lines charges and that "would leave consumers worse off because we expect retailers would pass the full value of the lines charge increase through to consumers, whilst retaining a portion of the LCE rebates received from Network Tasman. Mercury has estimated that retailers would retain 17% of all LCE payments they receive. Presumably as a windfall gain".

5.18 We do not think it is likely that retailers will be able to retain LCE rebates "as a windfall gain". While we agree that they might like to, we consider that over time, competition in the retail market will mean that they will have to pass through the value of any settlement residual rebate that they receive.[37] Instead, we consider that competition will provide an incentive for retailers to repackage all the costs they face - including charges for transmission services (ie, transmission charges, rebates and nodal prices) - into the form of charges that are most attractive to retail customers.

5.19 In addition, we consider that explicitly linking the payment of the settlement residual rebate to the payment of transmission charges would make more transparent that the settlement residual rebate is intended to offset the overpayment of the cost of transmission services.

5.20 Our current preference is therefore that the settlement residual rebate from each simple method region should be rebated against the transmission charges paid by a

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37 Unison submitted that "We have severe doubts that volatile LCE payments that are currently passed on to retailers by many EDBs are then being passed on to consumers via lower electricity retail prices: that would seem to be a commercially very risky proposition for a retailer to take a bet on." We agree that retailers would require a risk premium to take on a risky cash flow. This could be the case if we adopted the TPM charges approach to the SRAM. However, our preferred approach is the Simple BB SRAM. In this approach, the settlement residual rebate is intended to *reduce* the risk that the retailer faces by offsetting the cash flow effects of volatility in the nodal transport charge. This should reduce (rather than increase) the risk premium retailers seek.

distributor's customers for that region. That is because, as stated above, the rebate is intended to offset overcharging for transmission services used by each region.

5.21 This would require Transpower to identify the regional break-down of the distributor's settlement residual rebate for each distributor and require the distributor to match the rebate for each connection location to the pass-through of transmission charges to its customers.

5.22 However, under this option, we would mandate the pass-through but not the method of allocation. Instead, the Code would require the distributor in allocating the rebate to have regard to the intent that the rebate for each customer type be allocated in proportion to transmission charges paid by that customer type in respect of each connection location. This would allow distributors to weigh up this intent against other considerations, such as administrative complexity.

5.23 We have also considered whether the rebate should be passed through on a monthly basis, rather than annually. While this would better match the rebate to the transmission charge it relates to, we think rebate recipients would act as if it were matched to the associated transmission charge, provided they had certainty that they would get the rebate. We would therefore not mandate monthly pass-through. We think it quite likely that distributors would choose to match the timing of the pass-through to their normal billing cycle.

5.24 To complement this limited pass-through obligation, we think it would be desirable to:

(a) require Transpower to inform distributors of their rebate breakdown each month by location and (where applicable) by offtake vs. injection

(b) require distributors to disclose their current rebate methodology and its rationale

(c) require distributors to report each year on the application of their methodology, including by providing a breakdown of rebates by location and customer type

(d) provide ongoing oversight and guidance on rebate allocation methodologies as part of the Authority's work on distribution pricing.

5.25 This would ensure that distributors have the information they need to allocate the settlement residue as intended, and for retailers and others to ensure that they are paid what is intended.

5.26 We are also considering whether to include an explicit requirement for distributors to disclose to their customers that they are being credited with an allocation of settlement residual rebate and the amount (whether by way of explicit payment or by way of reduction of some other charge). This would enable customers to confirm or otherwise that they are being allocated a share of the rebate.

Full pass-through obligation

5.27 This option is the same as the limited pass-through obligation, except that:

(a) it would mandate the allocation of the settlement residual rebate at each grid connection location to distribution customers in proportion to each customer's transmission charges for that location

(b) it would mandate monthly pass-through.

5.28 This option has the advantage that it ensures the settlement residual rebate is closely tied to the overpayment for transmission services implicit in transmission charges.

5.29 It also has the advantage that it would ensure that different distributors would allocate settlement residue they receive in the same way, which means retailers that interact with multiple distributors would not have to take account of different methodologies in designing their systems.

5.30 However, this option has the disadvantage of imposing a one-size-fits-all requirement that some distributors may find difficult to accommodate – for example if they currently bundle transmission charges into their overall residual cost recovery.

Conclusion

5.31 Of the four options we have considered, only the limited pass through and full pass-through options ensure that distributors pass rebates on to their customers.

5.32 Of these, only the full pass-through obligation ensures that the rebate is appropriately matched with transmission charges. However, it also runs the risk of imposing unwarranted compliance costs. Moreover, we do not think it is necessary. We consider that requiring distributors to have regard to the intent that the rebate be allocated in proportion to transmission charges paid by each customer type in respect of each connection location provides sufficient incentive for distributors to allocate the rebate in accordance with its intent, while leaving flexibility for them to adopt a less targeted approach if that is warranted by other considerations.

5.33 We therefore propose to include a limited pass-through obligation in the Code. Appendix H includes proposed drafting to incorporate disclosure and pass-through obligations in the Code.

5.34 We have also provided that a party's allocation of settlement residue is a debt recoverable in a Court. This is to ensure that a party owed a rebate has the ability to seek redress directly if it is not paid.

Consultation questions

Do you agree that the Code should impose a limited pass-through obligation on distributors to pass-through any settlement residual rebate they receive?

Do you agree that they should be required to pass-through the settlement residual rebate to their customers rather than to, for example, end users?

Do you agree that the Code should require Transpower to inform distributors of their rebate breakdown each month by location and (where applicable) by offtake vs. injection

Do you agree that the Code should require the distributor, in passing through and allocating the rebate, to have regard to the intent that the rebate be allocated in proportion to transmission charges paid by each customer type in respect of each connection location?

Do you agree that distributors should be required to disclose their rebate methodology and its rationale, and to report on its application?

Do you think that distributors should be required to explicitly disclose to customers the amount of any allocation of settlement residual rebate they are being credited with at the time they are credited with it?

Do you agree the Code should require distributors to pass through rebates at least annually?

Do you have any other comments on this chapter?

6 Regulatory statement for the proposed amendments

Objective of the proposed amendments

6.1 The objective of the proposed Code amendment is to replace the current SRAM, which will become obsolete with the new TPM, with a new SRAM that is consistent with the Authority's statutory objective: to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers. In addition, the amendment aims to improve the effectiveness of the SRAM by introducing pass-through obligations for distributors.

The proposed amendments

6.2 The Authority proposes, subject to the results of consultation, to amend Part 14 of the Code as described in the preceding chapters of this paper and as laid out in Appendix H.

The proposed amendments' benefits are expected to outweigh the costs

6.3 The Authority has assessed the benefits and costs of the proposed Code amendments and expects them to deliver a net benefit. Over time, the proposed Code amendments would lead to relatively lower electricity prices for consumers.

6.4 Because the current SRAM will be made obsolete by the new TPM, it must be replaced.[38] We have therefore assessed the benefits and costs of the proposed SRAM compared to other potential SRAMs. The TPM charges option is in our view the next best option (after the proposed option), so we have used it as the counterfactual in our relative assessment of SRAM options. For pass-through, the counterfactual is the current approach where distributors are free to choose if and how to pass through rebates.

6.5 The Authority considers that the proposed SRAM option (the Simple BB option) would have higher net benefits than the other options considered. We also consider the proposed option of requiring enhanced disclosure and imposing a relatively non-prescriptive pass-through obligation will be more effective in supporting the SRAM than disclosure alone, and less costly than more prescriptive requirements. As discussed in detail below (and subject to consultation) our current assessment is that the proposal is likely to perform sufficiently better than the other options such that it should deliver significant net benefits.

Relative costs of Simple BB option

6.6 Transpower has indicated that the Simple BB option would cost approximately $0.5m more to implement than the TPM charges option.[39]

Relative benefits of Simple BB option

6.7 In our assessment, the Simple BB option delivers benefits relative to the TPM charges option in three key areas:

(a) investment coordination – the Simple BB option does not frustrate the objectives of the benefit-based charge in promoting efficient investment – any

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38 If the Authority did nothing, that would mean that Transpower would have to replace its current SRAM, since it refers to transmission charges that will no longer exist. As noted above, it is appropriate for the Authority to specify the SRAM, since the choice of SRAM affects the Authority's statutory objective.

39 Transpower's high-level estimate of the implementation cost for the TPM charges option is $0.65m.

user retains the correct incentive to take their exposure to future grid upgrade costs into account

(b) overpayment – the Simple BB option performs well in terms of reducing over-payment for transmission. It allocates LCE to parties using congested parts of the grid (who are exposed to nodal transport charges). The allocation is fixed, but broadly addresses over-payment for load and generation

(c) locational price risk – because the Simple BB option matches rebates to the parts of the grid where congestion occurs each month, it to some extent mitigates locational price risk for grid users.

6.8 We have not attempted to quantify the magnitude of these benefits; however, we have previously estimated a benefit of $179 million relating to more efficient investment brought about by the new TPM.[40] For Simple BB implementation costs to be warranted they need only make a 0.3% difference to this outcome in the worst-case scenario were there are no other benefits.[41]

Relative benefits and costs of distributor pass-through options

6.9 We have also considered options for ensuring distributor pass-through. Pass-through supports the effectiveness of the SRAM, since if distributors do not pass through the settlement residue, the SRAM does not achieve its objectives with respect to distribution-connected end users. We assess each option relative to the current approach where distributors are free to choose if and how to pass through rebates.

6.10 We consider the proposed option of requiring enhanced disclosure and imposing a relatively non-prescriptive pass-through obligation will be more effective in supporting the SRAM than disclosure alone, and less costly than more prescriptive requirements.

6.11 The costs of this option are:

(a) business process change – distributors who do not already pass settlement residue through to their customers will need to alter aspects of their existing business processes

(b) disclosure – distributors will need to publish their methodology for allocating settlement residue and publish annual breakdowns of allocation outcomes.

6.12 These costs will vary by distributor, being near zero for many and largest for distributors who do not currently allocate settlement residue to customers or do not have suitable documentation and accounting of their process – ie, costs will be highest where the benefit is greatest.

6.13 As an indication, if 29 distributors on average incurred a cost of $50,000 then the sector-wide cost would be $1.5 million, which means the proposal would need to make a 0.8% difference to the investment benefits noted above to be worthwhile

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40 Refer to benefits described as "more efficient investment, scrutiny, certainty" in Appendix D at https://www.ea.govt.nz/assets/dms-assets/29/Proposed-Transmission-Pricing-Methodology-Consultation-paper-v2.pdf

41 This illustration assumes that the benefits under the TPM charges option are zero – consistent with this option being used as the counterfactual in the relative assessment of options. As discussed in Chapter 4, we consider the benefits of the Simple BB option are significantly larger than those of the TPM charges option.

(assuming no other benefits). Putting the SRAM and pass-through proposals together, they would need to make only a 1.1% difference to the investment benefits noted above to be worthwhile (ie, to have positive net benefits, compared to the counterfactual). As discussed above (and subject to consultation) our current assessment is that the proposal is likely to perform sufficiently better than the other options such that it should deliver at least this level of net benefit.

6.14 We also considered:

(a) a more prescriptive pass-through option – this would impose more costs on more distributors, including those who already pass settlement residue through to their customers

(b) disclosure obligations only – these would impose more modest costs, but would be less likely to improve pass-through (and hence to support investment coordination and locational price risk benefits).

Alternative means of achieving the objective

6.15 The Authority has identified viable alternative means of addressing the proposed Code amendments' objective.

6.16 In addition to the alternative pass-through options and the TPM charges option described above, we also considered two other SRAM options:

(a) full BB – this would be significantly more complex to implement and operate than the Simple BB option. We consider that the extra benefits this option provides do not exceed the significant extra implementation costs involved

(b) wholesale market options – these options would involve higher transition costs but lower ongoing costs. However, these options produce significant disbenefits by undermining grid usage signals and harming investment coordination.

6.17 As discussed above, our current assessment (and subject to consultation) is that none of the alternatives considered are likely to be as effective in meeting the Authority's statutory objective as the proposed Code amendments.

The proposed amendments comply with section 32(1) of the Act

6.18 The Authority's objective under section 15 of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers.[42]

6.19 Section 32(1) of the Act says the Code may contain any provisions that are consistent with the Authority's objective and are necessary or desirable to promote one or all of the following:

Table 3: How the proposed amendment complies with section 32(1) of the Act

(a) competition in the electricity industry;	The proposed amendments are not expected to have a material impact on competition in the electricity industry.

42 See the qualification to this statement in footnote**Error! Bookmark not defined.**.

(b) the reliable supply of electricity to consumers;	The proposed amendments are not expected to have a material impact on the reliable supply of electricity to consumers.
(c) the efficient operation of the electricity industry;	The proposed amendments improve the efficient operation of the electricity industry by, at moderate cost: (a) better matching the charges for transmission services to the cost of providing them; (b) avoiding undermining grid usage signals; (c) avoiding undermining investment signals.
(d) the performance by the Authority of its functions;	The proposed amendments are not expected to have a material impact on the Authority's performance of its statutory functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendments will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

The Authority has given regard to the Code amendment principles

6.20 When considering Code amendments, we are required by our Consultation Charter[43] to have regard to the following Code amendment principles, to the extent we consider them to be applicable. Table 4 describes the Authority's regard for the Code amendment principles in the preparation of the proposed Code amendments.

Table 4: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposed amendments are lawful and consistent with the statutory objective and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The efficiency gains are set out in the evaluation of the costs and benefits.
3. Net benefits are quantified	An amendment to the SRAM is necessary as the current SRAM will become obsolete with the introduction of the new TPM. The benefits and

43 The consultation charter is one of the Authority's foundation documents and is available at: Foundation documents — Electricity Authority (ea.govt.nz)

Principle	Comment
	costs of the proposed SRAM and alternatives have been assessed qualitatively and the net benefit is expected to be positive compared to other options available.
4. Preference for small-scale 'trial and error' options	The preferred option is largely consistent with the principles of the existing SRAM.
5. Preference for greater competition	Not applicable.
6. Preference for market solutions	Not applicable.
7. Preference for flexibility to allow innovation	Not applicable.
8. Preference for non-prescriptive options	The Authority's preferred option for pass-through does not prescribe the method of pass-through.
9. Risk reporting	Not applicable.

Consultation questions

Do you agree with the objectives of the proposed amendments? If not, why not?

Do you agree the benefits of the proposed amendments outweigh their costs?

Do you agree that alternative means of meeting the objective are not as effective in meeting the Authority's statutory objective? If you disagree, please explain your preferred alternative option in terms consistent with the Authority's statutory objective.

Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

Do you have any other comments on this chapter?

Do you have any other feedback on any other aspect of this consultation paper?

Appendix A Current LCE and settlement residue

A.1 This appendix contains information on the revenue flows and elements that currently determine the total settlement residue that can be rebated.

A.2 As noted earlier in this paper, the wholesale electricity market generates a surplus, which is held by the clearing manager at the end of each month. In this appendix, we refer to this surplus as the WEM excess. The main contributor to the WEM excess is loss and constraint excess (LCE), which is the revenue from nodal transport charges (the difference in nodal prices between nodes). Figure 4 illustrates the cashflows:

(a) from the wholesale market to the clearing manager: a **WEM excess** (largely LCE);

(b) a portion of the WEM excess is made available by the clearing manager to the FTR market ('**FTR rentals**') – this is used, with FTR auction revenue, to make FTR payouts;

(c) funds flow back from the FTR market to the clearing manager ('**FTR excess**'), which are then passed on to Transpower;

(d) the portion of WEM excess that doesn't flow to the FTR market ('**non-FTR excess**') instead flows straight to Transpower;

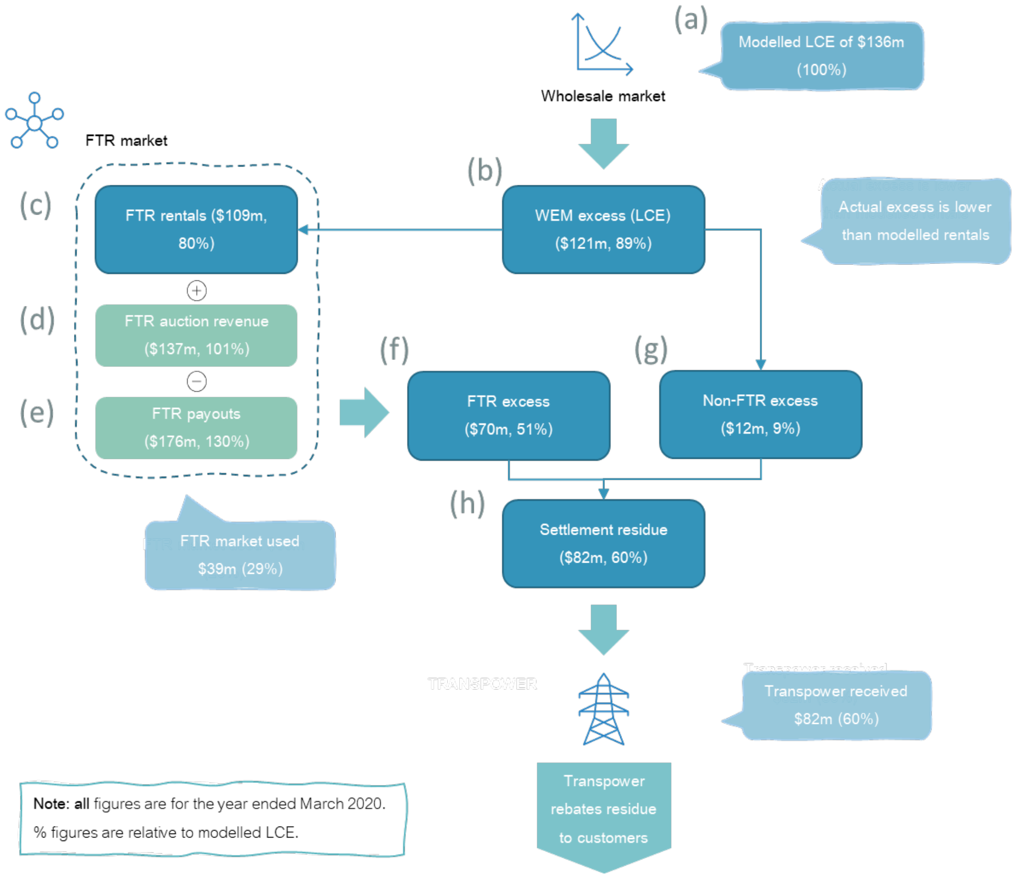
(e) Transpower receives both the FTR excess and the non-FTR excess, termed the **settlement residue** (also known as residual LCE), which it then rebates to grid customers.

A.3 These cashflows are illustrated below, with amounts and proportions from the year ending March 2020.

A.4 The settlement residue varies each month, driven by factors such as FTR market use (the final excess is lower if FTR pay-outs are high relative to FTR auction revenues, and vice versa) and due to additional cashflows that flow into the WEM excess (following the wholesale electricity market pricing and settlement processes due to other elements such as wash-ups and delayed settlements).

A.5 See below for further information on the revenue flows and what elements currently determine the total settlement residue that can be rebated.

Figure 4 Illustration of cashflows from wholesale market to Transpower



To explain the terms in Figure 4:

(a) modelled LCE – Transpower's assessment of expected LCE based on grid flows and prices[44]

(b) WEM excess – actual amount held by the clearing manager at month end

(c) FTR rentals – the portion of (b) allocated to the FTR market

(d) FTR auction revenue – proceeds from the sale of FTR products

(e) FTR payouts – payments to holders of FTR products

(f) FTR excess – (c), transformed by adding (d) and deducting (e)

(g) non-FTR excess – the portion of (b) not allocated to the FTR market

(h) settlement residue – the sum returned to Transpower, made up of (f) and (g).

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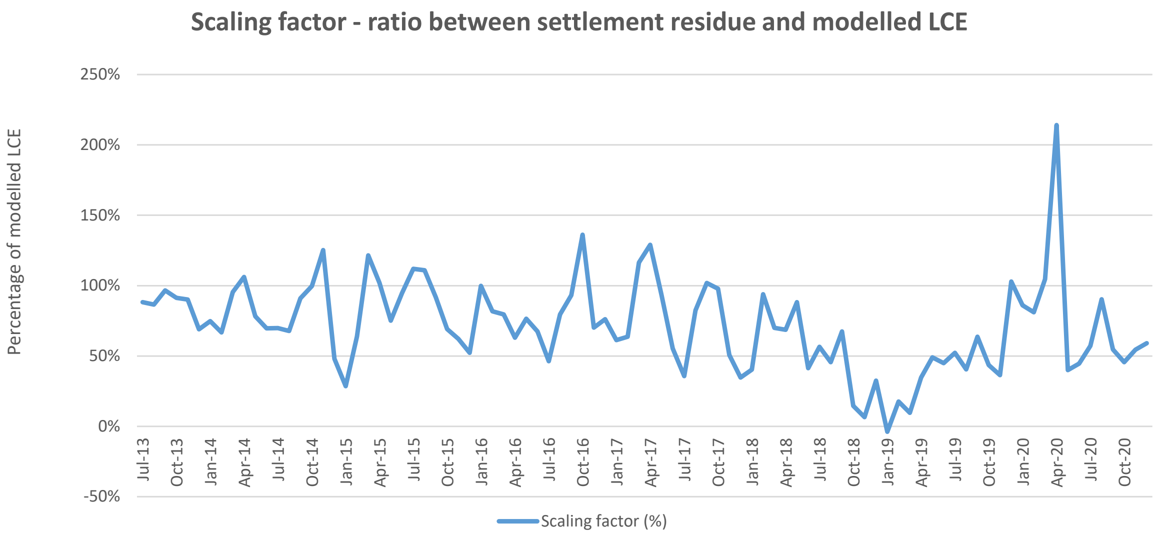
44 Transpower assesses modelled LCE in the first month after market settlement. This information is refined in later months for wholesale electricity market purposes, but Transpower does not reassess rebates or operate a wash-up process. As is shown below, Transpower publishes a 'scaling factor' each month that is the ratio between settlement residue and modelled LCE.

A.6 The following chart (Figure 5) shows monthly variation over the period for July 2013 to October 2020 in the scaling factor (the ratio between the settlement residue and modelled LCE). [45]

Figure 5: Settlement residue cashflows are volatile



45 Transpower publishes a regularly updated time series for the scaling factor on its website at [Pricing | Transpower]

Size of LCE compared to transmission charges

A.7 The following table compares historical revenue Transpower has recovered via transmission charges with the historical WEM excess – which is largely LCE.

Table 5 Settlement residue is a material part of overall transmission revenue

Item	Pricing Year (ending 31 March)						
	2014-15	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21[4]**
WEM excess (largely LCE)[1]	$53m	$56m	$68m	$87m	$124m	$121m	$140m
Settlement residue[1]	$43m	$56m	$55m	$63m	$43m	$83m	$80m
TPM revenue[2]	$944m	$918m	$943m	$991m	$942m	$927m	$786m
WEM excess (LCE), relative to TPM charges[3]	6%	6%	7%	9%	13%	13%	18%
Settlement residue relative to TPM charges	5%	6%	6%	6%	5%	9%	10%

Notes:

1. Cashflow figures sourced from the clearing manager.
2. TPM revenue sourced from Transpower information disclosures.
3. WEM excess (largely LCE), relative to TPM revenue.
4. For 2020-21 we assume actual LCE is 88% of modelled LCE.

A.8 The WEM excess has been relatively substantial when compared to Transpower's transmission charges in recent years. The proportion increased significantly for the 2021 pricing year because LCE was relatively higher than in previous years and because Transpower's maximum allowable revenue was reduced compared to previous years (via the RCP3 reset).[46]

[46] RCP3 refers to regulatory control period three, the five years from April 2020. A key driver of the reduction is prevailing low financing costs, which flow through to a reduced allowable rate of return.

Appendix B Arguments made in submissions

B.1 This appendix addresses the following arguments that were made in submissions:

(a) reducing volatility and preserving nodal price integrity are incompatible objectives;[47]

(b) the SRAM should not be used to address faults in the BBC;[48]

(c) residual charge is the best allocator;[49]

(d) all transport revenue should be used in the FTR market;[50]

(e) transport revenue is too small to worry about;[51]

(f) transport revenue should only be allocated to load;[52] and

(g) SRAM principles risk undermining the Authority's statutory objective.[53]

Reducing volatility and preserving nodal price integrity are incompatible objectives

B.2 This argument is incorrect because real-time nodal price signals are preserved if settlement residual rebates are *fixed* – nodal prices signal marginal costs, that is the cost of adding a unit of demand. If settlement residual rebates are fixed (ie, a user cannot alter the amount of rebate it receives by altering its behaviour) then they will not alter the cost of adding a unit of demand (or the payoff from reducing a unit of demand via generation or load curtailment). This is illustrated in Box 2 on page 9 and Appendix C.

B.3 This outcome is familiar from hedging products such as FTRs and CFDs. In all three cases, the user is shielded against the cash flow consequences of most of the volatility, while continuing to face the full price signal (and volatility) on increases or decreases in use relative to the hedged amount.

B.4 As such, the SRAM could in principle be used to reduce locational price risk without reducing the effectiveness of nodal prices. This is a worthwhile objective because reduced volatility means less risk and therefore lower costs.

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47 This issue was the subject of submissions by Electric Kiwi and Haast, ENA, Flick, Genesis, Network Tasman, Transpower, Unison, Vector and cross-submissions by Meridian and Transpower.

48 This issue was the subject of a submission by Entrust and a cross-submission by Trustpower.

49 This issue was the subject of submissions by Electric Kiwi and Haast, Entrust, Transpower, Vector and a cross-submission by Vector.

50 This issue was the subject of submissions by Electric Kiwi and Haast and cross-submissions by Contact, Electric Kiwi et al and MEUG.

51 This issue was the subject of submissions by Flick, Network Tasman and Nova.

52 This issue was the subject of submissions by Electric Kiwi and Haast, Entrust, Flick, MEUG, Nova, Transpower, Unison, Vector, WPI, and cross-submissions by Electric Kiwi et al, MEUG, Trustpower and Vector.

53 This issue was the subject of submissions by Network Tasman, Transpower and cross-submissions by Meridian, MEUG and Vector.

The SRAM should not be used to address faults in the BBC

B.5 This is not the reason for linking the SRAM to benefit-based charge (BBC) allocations.

B.6 The linkages between allocating transmission charges and transport revenue rebates have been long-recognised and were discussed in detail in the Authority's 2019 Issues Paper. There are linkages because:

a. Transport costs are recovered two ways – through the TPM and the transport component of nodal prices.[54] By design, the Commerce Commission regulatory regime requires the TPM to fully recover transmission costs. This means that it is necessary to return the settlement residue to transmission users to ensure they pay the cost of providing transport services but no more. If it were not returned, the additional charge would have the same adverse efficiency effect as an unpredictable and fluctuating sales tax on transmission services.

b. Lower net transport costs (nodal transport charge less rebate) are the main driver of benefits for most transmission investments. This means that the way rebates are allocated will affect how much transmission users benefit from a new transmission investment and so the allocation of BBCs. As such, there is an unavoidable need for a coherent relationship between BBC allocations, nodal transport charges, and rebates.[55] The benefit-based charge for an investment is allocated in proportion to the private benefits that transmission customers get from that investment. This means that the LCE generated by an investment should be returned to the parties that are assessed to benefit from the investment in proportion to those benefits. Any other allocation will cause a disjunct between the benefits provided by the transmission investment (leaving aside rebates) and the dis-benefits caused by loss of rebates.

c. If rebates are allocated in line with BBC allocations, then BBCs exhibit desirable exacerbator pays features by shielding parties from congestion *and* upgrade costs to the extent that their share of usage of a BBI does not grow beyond their BBC allocation for the investment.

Residual charge is the best allocator

B.7 Using the residual charge as the SRAM allocator would align with some SRAM principles (eg, not undermining grid usage signals), but has similar drawbacks to the TPM charges option, ie, it does not achieve any coherence between BBCs, transport charges and rebates. If the residual charge is used to allocate the settlement residue, it would mean the gain or loss each party gets from a new BBI would materially depend on their residual charge allocation, which is unrelated to their usage of the BBI. This means, for example, that all the parties who received a rebate of the transport revenue generated by a particular link but who made no use of the link,

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54 This is discussed in detail in Hogan Transmission *Investment Beneficiaries and Cost Allocation: New Zealand Electricity Authority Proposal* 2020, available at [TPM information papers and reports published — Electricity Authority (ea.govt.nz)]

55 The TPM provides Transpower with two variations on the standard method for allocating BBCs. The simpler variant uses flows as a proxy for benefits, while the more sophisticated variant explicitly evaluates prices and rebates.

would have a perverse incentive to oppose an efficient upgrade to the link because it would reduce the rebate they receive.

All transport revenue should be used in the FTR market

B.8 Most transport revenue is used in the FTR market already, but this largely exchanges transport revenues for auction revenues and leaves untouched the problem of how to allocate the settlement residue.

B.9 This consultation takes as given that there is settlement residue to be dealt with and is concerned with allocating it in a way that is consistent with the Authority's statutory objective. This question is being considered now because the existing SRAM will become obsolete when the new TPM is implemented.

B.10 The question of whether more (and potentially all) of the transport revenue should be used in support of the FTR market can be considered separately. It would best be considered in the context of the Authority's FTR workstream.[56] Any decision on this could not be implemented in time to remove the need for a replacement SRAM from 2023.

Transport revenue is too small to worry about

B.11 Transport revenues are a small percentage (less than 1%) of the total value traded through the wholesale electricity market, but this does not make the SRAM unimportant – it simply reflects that, on average, the grid is relatively uncongested.

B.12 However, the fact that transport revenues are small on average does not mean this is true always and everywhere. Transport revenues become relatively large and important in locations and at times when there is congestion. In those circumstances, transport charges and rebates have a critical role in coordinating grid access and investment and transport cost volatility adds significantly to overall nodal price risk. Poor allocation of settlement residual could therefore result in significant inefficiencies.

B.13 Furthermore, it is reasonable to expect grid congestion to increase over time, given increasing grid-connected generation and electrification of the economy. So, the SRAM is likely to become more important over time.

Transport revenue should only be allocated to load

B.14 This argument is advanced using some combination of the following points:

a. *Transport revenue is solely due to load over-paying*.

   This is incorrect. Congestion elevates downstream prices and suppresses upstream prices relative to what they would have been if there was no congestion. As such, generators contribute to the surplus by recovering reduced margins.

   Some submitters suggest that in the long run, generators can be expected to recover their costs, and for that reason, they argue, load pays all the transport costs in the long run. This argument neglects to account for the fact that distant

56 See https://www.ea.govt.nz/development/work-programme/risk-management/hedge-market-development/consultations/#c19182

generators, who bear the reduced margins, compete with local generators, who do not. This limits the ability of distant generators to pass on the reduced margin to load.[57]

b. *Allocation to generators would produce a windfall gain*.

This only appears to be the case if SRAM is considered in isolation from the TPM. As is illustrated under the heading *Customer impact* above, the new TPM increases charges for most generators, and this is partly offset by the SRAM allocation. These outcomes are consistent with access to rebates being the flip side of being allocated benefit-based charges.

c. *Allocation to generation would not benefit consumers*.

A well-designed SRAM should preserve the efficacy of nodal prices and enhance investment coordination. Both outcomes benefit consumers in the long term.

SRAM principles risk undermining the Authority's statutory objective

B.15 Some submitters were concerned that in proposing SRAM principles, the Authority is departing from its statutory objective and consultation charter. One concern was that the Authority might thereby exclude some options that were consistent with the statutory objective but inconsistent with the principles.

B.16 The Authority does not see the SRAM principles as replacing or limiting the statutory objective, but as an aid to applying the statutory objective in developing the SRAM. The Authority considers the principles are consistent with its statutory objective. The proposals in this paper have also been assessed for consistency with the statutory objective as required by section 32(1) of the Act.

[57] There is a parallel here with the TPM reform process: this point (competition between generators limits what charges can be passed on by generators to their customers) is also part of the Authority's rationale for charging generators benefit-based charges but not residual charges.

Appendix C Fixed rebate allocations do not undermine grid usage signals

C.1 The following calculations examine a user downstream of a congested link for which they have a fixed rebate share. Their net cost is the sum of their nodal transport and energy costs, less their rebate.

Flow across congested link	500	MWh	
Price separation across congested link	$50	per MWh	
LCE pool	$25,000		<- price difference X flow
User's rebate allocation	2%		
Nodal transport price	$25	per MWh	
Nodal energy price	$100	per MWh	
Nodal price	**$125**	per MWh	<- transport + energy
User's offtake	50	MWh	
User's transport cost	$1,250		<- nodal transport price X offtake
User's rebate	-$500		<- allocation X LCE pool
User's energy cost	$5,000		<- nodal energy price X offtake
User's total cost	$5,750		<- net transport + energy

C.2 Now the user increases their demand by one unit. The link is constrained – meaning flow across the link cannot increase – and hence the user's rebate is entirely fixed, and the nodal price signal is unaffected.[58]

User's new offtake	51	MWh	
User's transport cost	$1,275		<- nodal transport price X offtake
Users's rebate	-$500		<- allocation X LCE pool
User's energy cost	$5,100		
User's total cost	$5,875		
Increase in cost	$125		
Increase in offtake	1	MWh	
Price signal	**$125**	per MWh	<- nodal price signal preserved

58 If the link is near-constrained, then increasing demand will increase flows but these effects are second order and do not materially alter the price signal. If the party has market power, it may also increase price separation. This is discussed in the next appendix.

Appendix D Rebate incentives with market power

D.1 If a user does not have market power (ie, their actions won't change the price at their node), then a fixed rebate share (as under the Simple BB option) has:

(a) no impact on nodal price signals with respect to constrained parts of the grid;

(b) negligible impact with respect to congested but unconstrained parts of the grid (ie, where marginal losses are material but there is headroom to increase flows).

D.2 The situation is more nuanced if a user has market power (ie, if their actions will alter the price at the node):

(a) for parties using a congested link (ie, upstream generation and downstream load), having a fixed rebate share *reduces* the incentive to exercise market power. This is because profitable exercise of market power will reduce price separation, resulting in loss of rebate income.

(b) for other parties (ie, downstream generator or upstream load) the incentive to use market power is already constrained only by risk of retaliatory action. For example, a downstream generator with market power is restrained by the risk of provoking entry of competitors, exit of load or market conduct penalties. As such, the rebate does not alter incentives to exercise market power.

Appendix E How to make a submission

E.1 The Authority's preference is to receive submissions in electronic format (Microsoft Word). Submissions in electronic form should be emailed to network.pricing@ea.govt.nz with 'Consultation Paper— settlement residual allocation methodology' in the subject line.

E.2 If you cannot send your submission electronically, please contact the Authority at network.pricing@ea.govt.nz to discuss alternative arrangements.

E.3 Please note the Authority wants to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) Indicate which part should not be published.

(b) Explain why you consider that part should not be published.

(c) Provide a version of your submission that can be published (if the Authority agrees not to publish your full submission).

E.4 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

E.5 However, please note that all submissions received, including any parts that are not published, can be requested under the Official Information Act 1982. This means the Authority would be required to release material that was not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

E.6 Please deliver your submissions by **5pm** on **Tuesday 27 September 2022**.

E.7 We will acknowledge receipt of all submissions electronically. Please contact the Authority at network.pricing@ea.govt.nz or if you do not receive electronic acknowledgement of your submission within two business days.

Appendix F Break-down of near-term impact

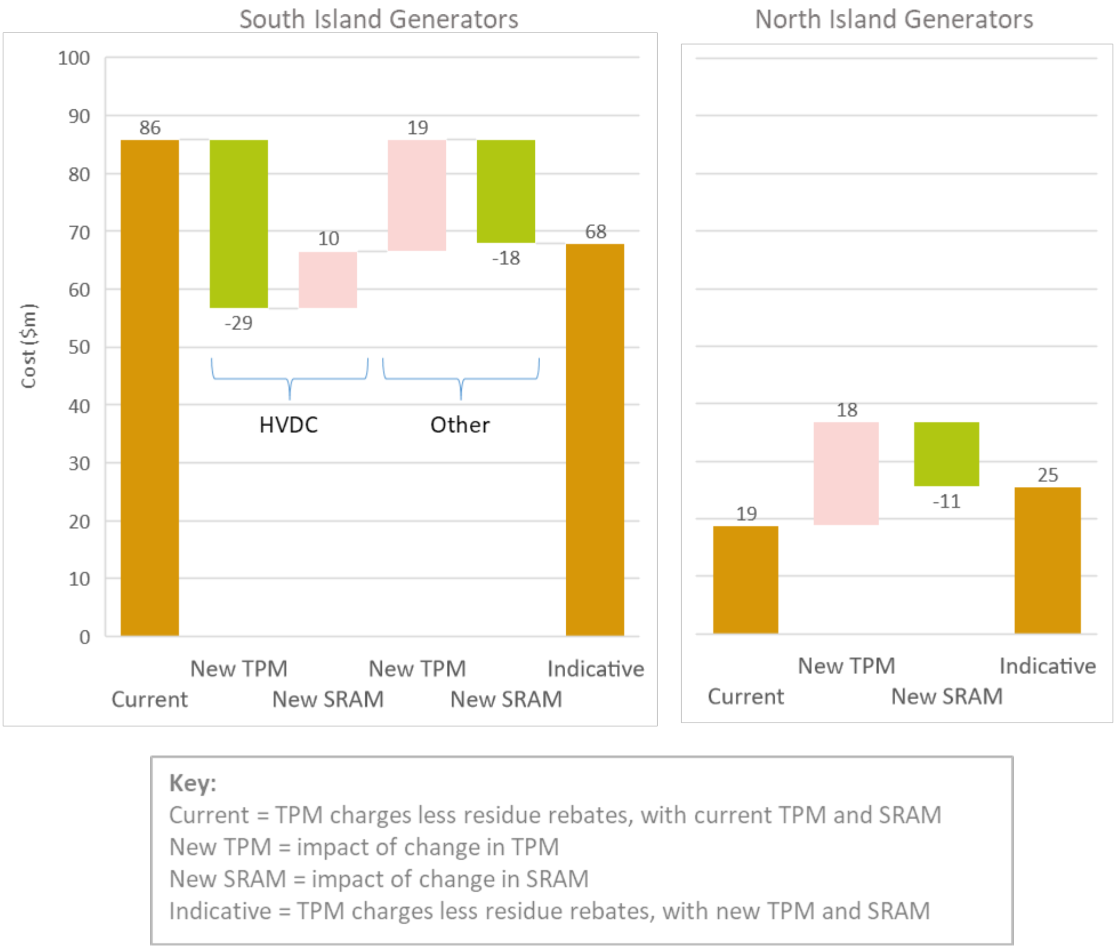
F.1 To provide additional context on the Simple BB option, the following chart illustrates the combined near-term impact on generators of changes in transmission charges (due to the new TPM) and changes in settlement residual allocation methodology.[59] The illustration breaks out three sets of changes:

(a) South Island generators (HVDC) – HVDC-related transmission charges reduce for South Island generators, and this is offset by reduced access to HVDC-related settlement residue

(b) South Island generators (balance) – other transmission charges increase, and this is offset by access to associated settlement residual rebates

(c) North Island generators – transmission charges increase, and this is offset by access to associated settlement residual rebates.

Figure 6 Near-term impact on generators of TPM and Simple BB changes



59 The modelling underlying this graph is published in the spreadsheet "SRAM impact assessment" on the Authority's website alongside this consultation paper.

Appendix G Questions to assist submitters

G.1 You are welcome to comment on any matter relevant to the Authority's proposal.

G.2 We have posed questions throughout the consultation paper to help prompt responses to specific aspects of the proposal. These are repeated here.

G.3 Please do not feel that you need to limit your responses to the consultation questions or that you need to answer them all. Please explain your answers in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

	Question
Chapter 2	Do you have any comments on the problem definition and background material in this chapter?
Response	
Chapter 3	Do you have comments on our proposed SRAM principles? Do you have comments on anything else in this chapter?
Response	
Chapter 4	Do you have comments on our preference for the Simple BB approach to the SRAM? Do you have any comments on our assessment of other SRAM options, including in particular the TPM charges method? Do you wish to propose another option for consideration? Do you have any comments on the proposed Code to incorporate the SRAM into the Code? In particular, do you have any comments on: • the proposal to make a party's allocation of settlement residue a debt recoverable in a Court? • the relationship between the Code Amendment, the benchmark agreement and transmission agreements? Do you have comments on anything else in this chapter?
Response	
Chapter 5	Do you agree that the Code should impose a limited pass-through obligation on distributors to pass-through any settlement residual rebate they receive? Do you agree that they should be required to pass-through the settlement residual rebate to their customers rather than to, for example, end users? Do you agree that the Code should require Transpower to inform distributors of their rebate breakdown each month by location and (where applicable) by offtake vs. injection Do you agree that the Code should require the distributor, in passing through and allocating the rebate, to have regard to the intent that the rebate be allocated region by region in proportion to

	transmission charges paid by each customer type in respect of each connection location? Do you agree that distributors should be required to disclose their rebate methodology and its rationale, and to report on its application? Do you think that distributors should be required to explicitly disclose to customers the amount of any allocation of settlement residual rebate they are being credited with at the time they are credited with it? Do you agree that the Code should require distributors to pass-through the rebate at least annually? Do you have any other comments on this chapter?
Response	
Chapter 6	Do you agree with the objectives of the proposed amendments? If not, why not? Do you agree the benefits of the proposed amendments outweigh their costs? Do you agree that the alternative means of meeting the objective are not as effective in meeting the Authority's statutory objective? If you disagree, please explain your preferred alternative option in terms consistent with the Authority's statutory objective. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act? Do you have any other comments on this chapter? Do you have any other feedback on any other aspect of this consultation paper?
Response	

Appendix H Proposed Code amendments

Electricity Industry Participation Code 2010

Part 1
Preliminary provisions

Contents

1.1 Interpretation

settlement residue is the **loss and constraint excess** and **residual loss and constraint excess** paid to a **grid owner** by the **clearing manager** under Part 14

Part 12A
Distributor agreements, ~~and~~ arrangements, and other provisions

Part 12A (other than clauses 12A.5B to 12A.5E): replaced, on 20 July 2020, by clause 7 of the Electricity Industry Participation Code Amendment (Default Distributor Agreement) 2020

Contents

12A.1 Contents of this Part

This Part—

(a) specifies requirements with which each **local network distributor** and each **trader** trading on the **distributor's network** must comply when entering into a **distributor agreement**; and

(b) specifies other requirements that apply to each **distributor** that has an **interposed arrangement** with 1 or more **traders**, and each **trader** trading on the **distributor's network**; and

(c) requires each **local network distributor** that has an **interposed arrangement** with 1 or more **traders** to develop and publish a **default distributor agreement** based on the relevant **default distributor agreement template**~~.~~; and

~~(c)~~(d) contains other provisions related to **distributors**.

12A.2 Participants to which the schedules to this Part apply ~~applies~~

(1) Each **distributor** described in a row in column 1 below, and each **participant** described in column 2 of the row, must comply with the provisions set out in each schedule referred to in column 3 of the row:

Row	Column 1 – Distributor	Column 2 – Participant	Column 3 – Schedule
1	Each **distributor** that owns or operates a **local network**, and has an **interposed arrangement** with 1 or more **traders** trading on the **local network**	Each **trader** that is a **retailer**, and is trading or wishes to trade at an **ICP** on the **network** of a **distributor** described in column 1 of this row	Schedule 12A.1 Schedule 12A.2 Schedule 12A.4
2	Each **distributor** that owns or operates an **embedded network**, and has an **interposed arrangement** with 1 or more **traders** trading on the **embedded network**	Each **trader** that is a **retailer**, and is trading or wishes to trade at an **ICP** on the **network** of a **distributor** described in column 1 of this row	Schedule 12A.2 Schedule 12A.3

(2) The schedules to this Part also specify requirements for appeals to the **Rulings Panel**.

12A.3 Distributors must pass-through settlement residue

(1) The purpose of this clause is to allocate **settlement residue** to **consumers** (or **retailers** on behalf of **consumers**) in proportion to the transmission charges paid by those **consumers** (whether directly or indirectly) [in respect of each **connection location**]. [*Text in square brackets is for the "Simple BB option" only*]

(2) A **distributor** that is paid any amount of **settlement residue** under clause 14.35A(1) of Part 14 must, at least annually, allocate and pay this amount to its customers in accordance with a methodology developed under subclause (3).

(3) Each **distributor** to whom subclause (2) applies must develop a methodology for allocating **settlement residue** to its customers that has regard to the purpose described in subclause (1) [and the information provided to the distributor by **Transpower** under

clause 14.35A(7) of Part 14]. [*Text in square brackets is for the "Simple BB option" only*]

(4) A **distributor** must publish the methodology developed under subclause (3), including an explanation of the rationale for the methodology.

(5) A **distributor** must publish annually a breakdown of payments made under subclause (2) by location and type of customer (for example retailer, direct generation customer, direct load customer).

(6) A **distributor** may adjust any payment made under subclause (2) to correct for a previous overpayment or underpayment under that subclause.

(7) An amount payable under subclause (2) is recoverable in any court of competent jurisdiction as a debt due to the person to whom that subclause requires payment to be made.

(8) A payment required under subclause (2) may be met by way of a credit against any amount owed to the **distributor** by the customer.

Part 14
Clearing and settlement

14.35 Payment of residual loss and constraint excess

Each **grid owner** must treat **residual loss and constraint excess** paid to it under this Part as **loss and constraint excess**.

"TPM charges option"

14.35A Allocation and payment of settlement residue by grid owner

(1) Each **grid owner** must allocate and pay any **settlement residue** to its customers on a monthly basis in accordance with a methodology developed under subclause (2), or if the **grid owner** is **Transpower**, subclause (3).

(2) Each **grid owner** must develop a methodology for allocating **settlement residue** to its customers such that the amount allocated to any customer is in proportion to that customer's share of the total charges for using the **grid owner's** part of the **grid**.

(3) **Transpower** must develop a methodology for allocating **settlement residue** to its customers such that the amount allocated to any customer is in proportion to that customer's share of the total charges allocated under the **transmission pricing methodology**.

(4) A **grid owner** may adjust any payment made under subclause (1) to correct for a previous overpayment or underpayment under that subclause.

(5) An amount payable under subclause (1) is recoverable in any court of competent jurisdiction as a debt due to the person to whom that subclause requires payment to be made.

(6) A payment required under subclause (1) may be met by way of a credit against any amount owed to the **grid owner** by the customer.

"Simple BB option"

14.35A Allocation and payment of settlement residue by grid owner

(1) Each **grid owner** must allocate and pay any **settlement residue** to its customers on a monthly basis in accordance with a methodology developed under subclause (2), or if the **grid owner** is **Transpower**, subclause (3).

(2) Each **grid owner** must develop a methodology for allocating **settlement residue** to its customers such that the amount allocated to any customer is in proportion to that

customer's share of the total charges for using the **grid owner's** part of the **grid**.

(3) **Transpower** must develop a methodology for allocating **settlement residue** to its customers such that the amount to be allocated to any customer is calculated by—

- (a) dividing the **settlement residue** into portions related to—
  - (i) each connection asset; and
  - (ii) the interconnection assets in each modelled region under the simple method~~:~~; and
- (b) allocating **settlement residue** related to each connection asset to the **designated transmission customers** connected to it; and
- (c) allocating the **settlement residue** related to each modelled region under the simple method to the beneficiaries of transmission investments in the modelled region under the simple method.

(4) A **grid owner** may adjust any payment made under subclause (1) to correct for a previous overpayment or underpayment under that subclause.

(5) An amount payable under subclause (1) is recoverable in any court of competent jurisdiction as a debt due to the person to whom that subclause requires payment to be made.

(6) A payment required under subclause (1) may be met by way of a credit against any amount owed to the **grid owner** by the customer.

(7) **Transpower** must disclose monthly to a **distributor** the following information about any payment made to the **distributor** under subclause (1)—

- (a) the **connection location** it relates to; and
- (b) where applicable, whether it relates to **offtake** or **grid injection**.

(8) In subclause (3)—

- (a) "beneficiaries", "connection asset", "interconnection asset", "modelled region", "simple method" and "transmission investments" have the meanings set out in the **transmission pricing methodology**; and
- (b) whether a **designated transmission customer** is "connected to" a connection asset is determined under the **transmission pricing methodology**.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
Authority	Electricity Authority
BB	Benefit-based
BBC	Benefit-based charge
BBI	Benefit-based investment
Code	Electricity Industry Participation Code 2010
SRAM	Settlement Residual Allocation Methodology
FTR	Financial transmission rights
HVDC	High voltage direct current
LCE	Loss and constraint excess
RCP3	Regulatory Control Period 3 (the five years from April 2021)
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited
WEM	Wholesale electricity market

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