Avoided Cost of Transmission (ACOT) – proposed TPM-related amendments

Consultation paper

September 2022

Submissions close: 5pm **20 October 2022**

Executive summary

Certain pre-2017 distributed generators are currently eligible for payments from distributors for avoided costs of transmission (ACOT).[1] ACOT payments, which are addressed in Part 6 of the Code, are a recoverable cost for distributors. In the year ended 31 March 2021, distributors paid approximately $35 million to distributed generators and recovered this amount from other distribution customers (and ultimately from electricity consumers).

The vast majority of ACOT payments are based on avoided interconnection charges, essentially recognising reduction in peak period usage by distributors or directly connected industrial consumers, under the current transmission pricing methodology (TPM). The Authority has previously expressed concern that these payments are inefficient and are largely funding charge avoidance rather than cost reduction, ie, the payments don't result in less transmission investment, meaning Transpower will need to recover the same revenue but from other consumers.

When the Authority reviewed this issue in 2016, it limited eligibility for ACOT payments but did not establish a permanent resolution to the problems identified with ACOT payments because TPM reform was underway and relevant to longer-term settings – including because a primary goal of TPM reform was to remove incentives for inefficient charge avoidance.

From April 2023, the current TPM will be replaced with a new TPM that, by design, does not include any usage-based charges. This is consistent with the view that nodal prices send an efficient signal for coordinating usage, and investment is best coordinated through nodal prices and exposure to a (benefit-based) share of future upgrade costs.

Clarifying present and longer-term settings

In the context of the Authority's wider concern about the ACOT regime, the new TPM presents an immediate need to ensure the Code clearly supports efficient pricing. The interconnection charge that has historically provided the basis for ACOT payments will no longer exist, so this will prompt parties to reconsider their ACOT obligations and entitlements.

Our preferred approach is to amend the Code to provide explicitly that ACOT payments are no longer required. This is consistent with the intent of the new TPM that transmission charges should not influence usage. This would also make clear that the following alternative approaches to ACOT payments are not available:

a) payments based on the limited charge avoidance opportunities that remain in the new TPM

b) payments based on forward-looking assessments of future transmission charges.

While the Authority's proposed Code amendment, if adopted, would mean that ACOT payments do not continue, there may still be a future role for regulated price signals for grid support technologies. Ensuring that any such price signals would be efficient and competitively neutral is far from straightforward. As such, whether such an approach could have a limited role in future, and with appropriate safeguards, is best considered as part of longer-term work that examines matters such as network and technology neutrality, the effectiveness of network pricing signals for distributed generation, and the balance between Transpower's role and the role of distributors. This paper provides some context on this wider work and invites views.

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1 More than 7,500 distributed generators, all installed prior to 2017, are currently listed as eligible. Refer https://www.emi.ea.govt.nz/Wholesale/Datasets/_AdditionalInformation/SupportingInformationAndAnalysis/2018/DistributedGenerationEligibleToQualifyForACOT

Considering transition risks

It is prudent to consider whether the transition away from recoverable ACOT payments poses any material risks.

We are satisfied that there is little risk of harm arising through damage to investor confidence, because the transition has been well signalled and efficiency is enhanced if investors do not rely on continuation of inefficient payments.

We are also reasonably confident that the transition should not present a reliability risk, because distributed generators are unlikely to cease operation due to the proposed Code amendment, nodal prices will signal the value of generation, and Transpower retains some ability to pay distributed generators directly if that provides a lower cost (or more feasible) solution than investing in transmission.

However, any residual risk to reliability could be mitigated if ACOT payment obligations were phased out, rather than stopping completely from April 2023. As such, we are consulting on whether, as an alternative, we should introduce transition arrangements that would reduce the rate for ACOT payments from 100% this (pricing) year to 50% next year, 25% the following year, and then zero. This phase-out profile could provide time for Transpower to better gauge and respond to any reliability risk but would involve consumers paying on the order of $20 million for insurance that appears to be of questionable value.

On balance, our preference is to remove ACOT payment obligations from April 2023, based on the efficiency and competition benefits. This is a matter of judgement, and we invite views on whether a phase out would be preferable.

Contents

1 Introduction

Making a submission

1.1 Please see Appendix D for details on how and by when you can make a submission on this proposal. Appendix E collates all the consultation questions set out in this document. Submissions are due by 5pm, **20 October 2022**. We plan to publish submissions on 21 October and invite cross-submissions by 3 November 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 the consideration of this consultation paper.

Table 1 Key sources of information relevant to this proposal

ITEM	REFERENCE
The Authority's 2016 review of distributed generation pricing principles	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-of-part-6-distributed-generation-pricing-principles/
The Authority's project to determine which generation would remain eligible for ACOT payments	https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/
Transpower's engagement on its processes for transmission alternatives	https://www.transpower.co.nz/keeping-you-connected/industry/transmission-alternatives
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 project to consider whether to propose a transitional congestion charge	https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/tpm-development-project-exploring-transitional

1.4 In the remainder of this paper, we discuss:

(a) the background and context for this proposed Code amendment regarding ACOT payments

(b) our proposal to clarify that ACOT payments will not be required from April 2023

(c) our consideration of transition risk, and whether phase-out is warranted

(d) our plans for considering related matters (including with respect to distribution pricing) in future.

2 Background and context

2.1 This section provides background information and relevant context regarding ACOT payments to distributed generators. We provide more detailed background information in Appendix A.

Distributed generation access rules

2.2 "Distributed generation" (DG) refers to generation connected to a distribution network. Part 6 of the Code provides an access framework for DG, which includes distributed generation pricing principles (DGPPs) that distributors must apply.

2.3 The DGPPs were originally developed as part of regulations passed in 2007 that were intended to encourage investment in small-scale electricity generation. Accordingly, they establish favourable pricing arrangements for DG that include:

(a) pricing based on the incremental costs of connecting the DG to the distribution network only – ie, no contribution to distribution network common costs

(b) payment for 100% of avoided costs – distributors pay DG the full value of any costs they avoid due to the presence of the DG. These include avoided costs of distribution (ACOD) and avoided costs of transmission (ACOT).

2.4 The Authority amended the DGPPs in 2016 to restrict ACOT payments. The Authority was concerned that payments were inefficiently high, including because they were typically based on avoided transmission charges rather than avoiding underlying costs. Because Transpower's revenues are regulated, charges avoided by one distributor simply transfer to other transmission customers – with the result that consumers pay more overall (ultimately paying for both transmission charges and ACOT payments).

2.5 The 2016 amendment established an interim position that restricted eligibility for ACOT payments to certain pre-2017 DG, as the Authority recognised that an enduring position should follow conclusion of the TPM reform process then underway.

2.6 Following the 2016 amendment, the Authority published lists of DG that would remain eligible for ACOT payments. The lists were informed by what was effectively a high-level assessment of locations in the grid where DG potentially contributes to grid reliability – ie, the lists are not confirmation that any given DG is essential to reliability (or that ACOT payments are required to ensure its ongoing operation).

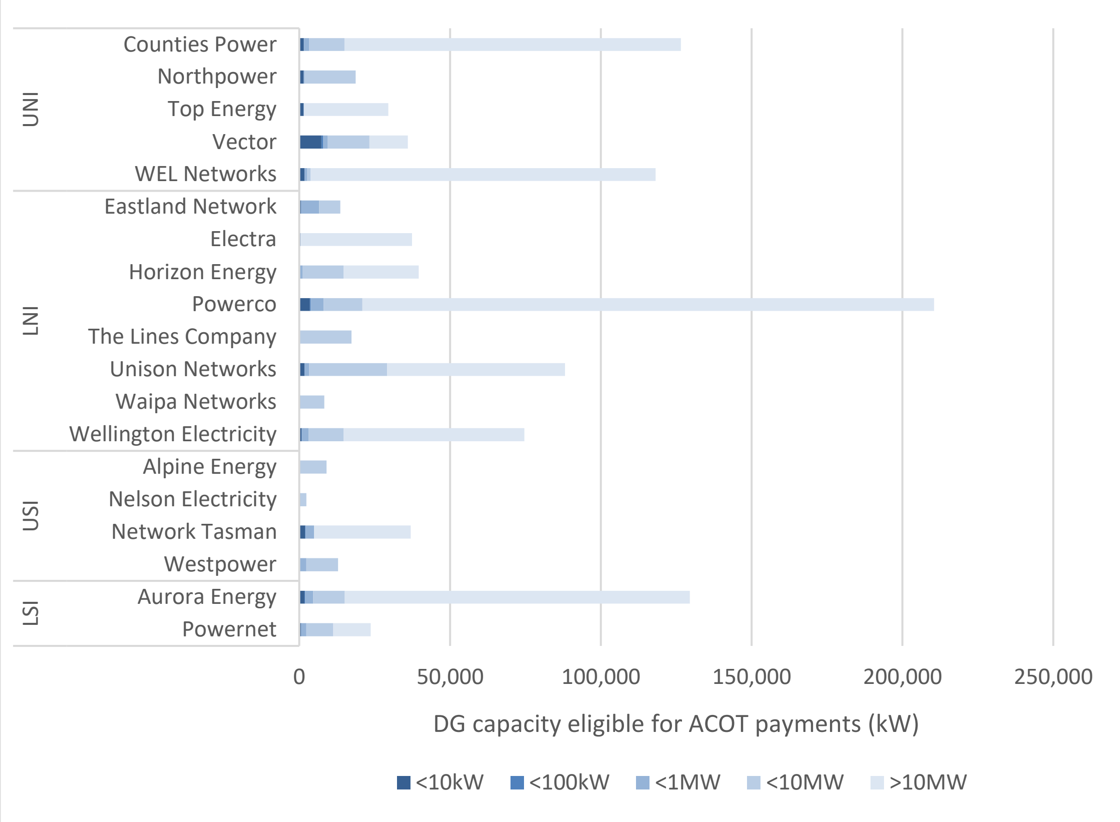
ACOT payments

2.7 In total there are 7,590 installations on the DG lists, with an overall capacity of 1,033 MW.[2] Of the eligible capacity, only 5% comes from 7,527 smaller generators (with capacity of 1 MW or less) and 77% is from 20 very large generators (with capacity of 10 MW or more).[3]

[2] This included 661 generation installations in the LSI, 651 in the USI, 2,582 in the LNI, and 3,696 in the UNI. The lists are available here: [Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)]

[3] DG on the lists is eligible to qualify to receive ACOT payments. However, a DG that is included on the list does not necessarily receive ACOT payments. DG receiving ACOT payments are a subset of those eligible.

Figure 1 Over 1GW of distributed generation is eligible for ACOT payments



2.8 For price-quality regulated distributors, ACOT payments are a recoverable cost.[4] This means they can add ACOT payments to their target revenue, which they recover from consumers.

2.9 ACOT payments have typically been based on Transpower's interconnection rate, which was $96.89 per kW for the 2022/23 pricing year.[5] For context, ACOT payments amounted to $35 million for the year ended 31 March 2021, funded through uplifts in lines charges.[6] Transpower's interconnection revenue is $590 million for the 2022/23 pricing year, so ACOT payments on the order of $35 million would add around 6% to interconnection charges.[7]

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4 See clause 3.1.3(f) of the Electricity Distribution Services Input Methodologies Determination 2012 at https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf

5 2022/23 refers to the 12 months ending 31 March 2023. The "interconnection rate" is often referred to as the regional coincident peak demand (or RCPD) rate.

6 ACOT payments have typically been based on actual production during the top 100 demand periods for each of four regions. Generators vary in their ability and willingness to target those periods. For the year ended 31 March 2021, distributors recovered $35 million from their customers for distributed generation allowances, which covers ACOT payments. Source: EDB information disclosures, Schedule 3, https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/information-disclosed-by-electricity-distributors

7 Transpower pricing data https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Rates%20Table%20April%202022.pdf

TPM reform

2.10 From April 2023, the current TPM will be replaced with a new TPM that, by design, only includes fixed-like (as opposed to usage-based) charges. This is in contrast with the existing TPM, which includes an interconnection charge that updates annually based on recent peak demand measures. The usage-based interconnection charge has been the basis for the vast majority of ACOT payments.

2.11 This design approach of the new TPM is consistent with a view that:

(a) nodal prices provide an efficient signal for coordinating grid usage

(b) transmission charges should avoid further influencing usage (because that reduces efficiency), and

(c) investment is best coordinated though nodal prices combined with exposure to the prospect of sharing in the cost of future grid upgrades.

2.12 The TPM guidelines provide Transpower with an option to propose certain usage-based charges in future (reflecting costs which it might be logical to signal to distributed generation), but these charges are not included in the new TPM, will not be in place at the time the new TPM is implemented and are not currently under development. The possible usage-based charges are:

(a) transitional congestion charge, and

(b) kVAr charge.

2.13 The Authority's consultation on TPM reform has included discussion of ACOT implications. The consultation (and submissions) is summarised in Appendix B.

Consultation questions

Do you have any comments on the background and context material in this chapter or Appendix A?

3 We propose to remove provisions for ACOT payments from DG pricing principles

3.1 The new TPM:

(a) removes the interconnection charge, and

(b) alters the way nodal prices and transmission charges work together to coordinate usage and investment, including by generators.

3.2 This means we should revisit the ACOT provisions in Part 6 of the Code ahead of April 2023 to ensure:

(a) clarity – removal of the interconnection charge will prompt parties to revisit the ACOT rules to determine their obligations and entitlements. Ensuring requirements are clearly expressed helps ensure an efficient transition, including by mitigating risk of disputes

(b) efficient pricing – pricing arrangements (including nodal pricing, transmission charges, distribution charges and payments) should work together to promote competition, reliability, and efficiency.

Problem definition

3.3 If we do not amend the Code, then the potential problems that arise are:

(a) unnecessary administrative costs – while we expect most participants would reach the view that ACOT payments are no longer required even without the Code change, reaching this position may incur costs associated with seeking advice and, potentially, resolving disputes (between distributors and distributed generators)

(b) inefficient payments – some participants might reach a view that ACOT payments linked to allocator updates or future investments may be warranted.

(i) payments linked to allocator updates would be inefficient – funding unproductive charge avoidance and potentially undermining nodal pricing signals

(ii) payments linked to future investments would have a high likelihood of being inefficient – either resulting in unnecessary payments (for actions that would have occurred anyway) or funding a less efficient outcome (than relying on nodal prices and Transpower's incentives to find least-cost solutions).

3.4 The following sections set out more detail on these problems.

Preferred approach

3.5 Our preferred approach is to amend the Code to clarify that ACOT payments are not required, meaning that price-quality regulated distributors will not be able to treat ACOT payments as a recoverable cost when determining their target revenue.[8]

[8] It is possible that some distributors may have contractual obligations that survive removal of the Code obligation to make ACOT payments, however the cost of such payments would no longer be passed to consumers.

3.6 This is consistent with the approach we consulted on as we developed the guidelines for the new TPM.[9] It recognises that all the charge types included in the new TPM are designed to avoid influencing usage:

(a) connection charges are based on asset values, and recover the cost of dedicated assets from the parties who use those assets to access the grid

(b) standard method benefit-based charges (standard BBCs) are based on a one-off forward-looking assessment of who is expected to benefit from a new investment. Once the investment is made, cost allocation is largely fixed[10]

(c) simple method BBCs recover the cost of lower-cost grid investments[11]

(d) residual charges are used to recover any other costs (ie, not recovered through connection or benefit-based charges) from load (based on a lagging measure of gross demand – ie, distributed generation should not influence the charge).

3.7 In the same way that it is efficient that grid usage by load and grid-connected generators is not influenced by these charges, we consider it is also efficient that usage by distributed generation is not influenced by them (ie, through linkage to ACOT payments).

3.8 Distributed generation is exposed to nodal prices in the same way as grid-connected generation, and the transport component of nodal prices provides an efficient signal regarding the location, timing, and severity of grid congestion. If distributed generation is downstream of a congested part of the transmission network, it can access elevated prices for energy it produces at that time.[12] The Authority is also implementing changes to nodal pricing that will improve effectiveness, including by removing barriers to distributed generators offering into the market[13]. This means distributed generators can set a price that should ensure they recover their operating costs whenever they are required to alleviate a transmission constraint (after generation and demand response with lower bid and offer prices have been dispatched).

3.9 There is also the potential for distributed generation to sell grid support services to Transpower if this provides a lower-cost alternative for Transpower than investing in grid assets.[14]

3.10 If Transpower does propose the addition of usage-based congestion or kVAr charges to the TPM in future, then it would be appropriate for the Authority to consider whether and

[9] Refer Appendix F of the 2019 TPM issues paper (https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf).

[10] Given that the new transmission charges will be largely fixed, any ACOT payments based on those charges would not provide additional incentives for distributed generation to operate during peak periods.

[11] These are typically routine lifecycle investments to maintain the operation of existing capacity.

[12] There are a variety of ways that nodal price signals can flow to distributed generators – eg, directly (if the generator participates in the wholesale market), via retailer-determined prices paid for injection (which are influenced by nodal prices) or via prices paid by load (if embedded).

[13] The Dispatch Notification scheme being introduced as part of the Authority's real time pricing project removes barriers to small-scale participants, including distributed generators, from offering into the wholesale market, including by not requiring real time indications, allowing dispatch via web services, reducing compliance overhead, and allowing small-scale DG behind a single grid exit point to be offered in aggregate. More information on the Dispatch notification scheme can be found here: Real time pricing industry engagement sessions — Electricity Authority.

[14] Transpower has an obligation to consider transmission alternatives when evaluating major grid upgrades. For lower-cost grid upgrades, Transpower has incentives to find least cost solutions within its regulated price-quality path set by the Commerce Commission.

how those charges might be signalled to distributed generation at that time. Otherwise though, the logic of the new TPM does not support ongoing ACOT payments to distributed generation, including those currently on the ACOT lists.

3.11 The Authority's view is that amending the Code to clarify that ACOT payments are not required will promote the Authority's statutory objective in terms of:

(a) efficiency – the risk that the cost of inefficient ACOT payments will be recovered from consumers will be removed, and administrative costs associated with the transition to a new TPM will be reduced

(b) competition – removing ACOT payment obligations levels the playing field between pre-2017 and new DG, and between DG and other transmission alternative providers (including grid-connected generation, and other technologies that can provide flexibility)

(c) reliability – the amendment is unlikely to significantly alter grid reliability, as nodal prices will still incentivise operation and Transpower can still contract directly for grid support. We have considered an alternative that could mitigate reliability risk by phasing out payments – this is discussed in Section 4.

Inefficient payments

3.12 Absent amendment, there are two potential arguments that might be used to justify ongoing ACOT payments given the new TPM:

(a) allocator updates – there are, for various practical reasons, some weak links between usage and charges in the new TPM. Most notably, the allocators used for simple BBCs are updated five-yearly based on analysis of historical grid flows. This means that a sustained reduction in grid usage can eventually flow through to lower BBCs for future low-cost grid investments[15]

(b) future investments[16] – altering usage could influence the timing or scale of a future grid investment, or the amount that a user is assessed to benefit from that investment. This would flow through to lower BBC allocations for that investment in future (or to a deferral of BBCs).[17]

3.13 We consider that making ACOT payments based on allocator updates would be inefficient, and contrary to the intent of the TPM. This would involve making ACOT payments to support charge avoidance, with no link to underlying transmission investment (ie, economic costs). In other words, if such payments were successful at reducing a distributor's transmission charges then the outcomes would be:

(a) no change in charges for that distributor's customers (as they would be paying for the ACOT payments instead of paying for the avoided transmission charges)

(b) an increase in charges for other transmission customers

[15] The other case is where connection assets are shared between two or more parties, in which case costs are allocated between those parties based on anytime maximum demand or injection.

[16] We don't think it is practical (or efficient) for parties to base ACOT payments on reverse-engineering the allocation process for charges they already receive for investments Transpower has already made.

[17] If the investment is in a connection asset, then the same logic applies but to connection charges (or new investment contract payments).

(c) nationwide, an overall increase in the amount consumers pay for electricity lines services

(d) no change in Transpower's costs (or revenue).

3.14 Making ACOT payments based on exposure to the costs of future investments is more consistent with the forward-looking intent of the new TPM, but adoption of this approach would be problematic because:

(a) assessing ACOT payments based on their impact on future investments, and therefore the distributor's exposure to BBCs, would be far from straightforward. There are varying 'depths' to which such assessment could be carried out, and no objectively correct answer. Determining ACOT values this way would be difficult and contentious for distributors and distributed generators

(b) it is not clear the resulting payments would be efficient, including because they may:

(i) not ensure reasonable pricing neutrality between grid-connected generation and distributed generation, or between distributed generation and other technologies that can provide flexibility services[18]

(ii) result in unnecessary payments that don't alter grid investment, or that compensate generators that would have invested anyway without ACOT payments

(iii) insert distributors into a transaction that could instead be funded directly by Transpower, with costs recovered across a wider set of beneficiaries.

3.15 Whether this approach or some other method of price signalling to distributed generators could have a limited role in future, and with appropriate safeguards, is best considered as part of longer-term work that examines matters such as network and technology neutrality, the effectiveness of network pricing signals for distributed generation, and the balance between Transpower's role and the role of distributors.

3.16 We include introductory discussion of these future considerations in section 5 and Appendix C, and invite any views that could assist the Authority as we develop this thinking further.

3.17 We consider that it would aid certainty and help to reduce the risk of disputes (and the risk of inefficient payments) if we amend the Code to plainly set out that there is no basis for ACOT payments, which would also preclude either of the above approaches.

Proposed amendments

3.18 We attach proposed amendments to the Code at Appendix F. The proposed amendments:

(a) modify the definition of incremental costs to make it clearer[19], and to consolidate material into the definition

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18 Neutrality is important given significant investment is expected across the sector in coming decades to meet electrification-driven demand growth, and pricing settings will influence the efficiency of that investment.

19 One of the changes we have proposed to clarify the Code is to remove the words "with connection services" from the definition of incremental costs as we felt these words were redundant. For the avoidance of doubt, this clarification is not intended to alter in any way the Code requirements that refer to the definition of

(b) remove reference to netting off transmission costs

(c) make consequential changes to Schedule 6.4.

3.19 These changes are intended to:

(a) make the impact of the new TPM on ACOT payments clear for distributors, DG, and distribution customers

(b) reduce the likelihood of dispute between distributors and DG as to the impact of the new TPM on ACOT payments

(c) ensure ACOT payments are no longer a recoverable cost for price-quality regulated distributors. This means those distributors cannot add the cost of ACOT payments to their target revenue for recovery from consumers.[20]

3.20 In addition to our proposed amendment, we have included further drafting that could be used to phase-out ACOT payments. This is discussed in Section 4 below.

Consultation questions

Do you agree with the Authority's preferred approach of clarifying that ACOT payments are no longer required?

Do you have any comments on the alternative approaches that could be used to justify ACOT payments?

Do you have any comments on the Authority's proposed amendments to the Code?

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incremental cost. Through submissions, we would be interested to hear any views on whether this clarification could on its own result in altered interpretations of the Code requirements.

20 Distributors that meet a certain definition of 'consumer owned' are exempt from price-quality regulation (but subject to information disclosure). For a list of exempt distributors refer: https://comcom.govt.nz/regulated-industries/electricity-lines/our-role-in-electricity-lines/consumer-owned-electricity-distribution-businesses

4 Alternative option – phase out could mitigate transition risk

4.1 With the Authority's proposed amendments, the Code would unambiguously provide that there is no Part 6 obligation for distributors to make ACOT payments from April 2023. This means that ACOT payments would no longer be a recoverable cost for distributors.

4.2 While we are confident this is an efficient outcome, it is prudent to consider whether terminating ACOT payments could present transition risks. We have considered two key risks:

(a) investor confidence – terminating cashflows has the potential to dent investor confidence, which can be harmful longer-term

(b) reliability – terminating cashflows could potentially alter availability of distributed generation, which could in turn present a grid reliability risk.[21]

4.3 We are confident that investor confidence risks do not justify an alternative approach in this instance. It has been well signalled for many years that current ACOT payment settings would be subject to further review and that, absent transitional congestion or kVAr charges in the new TPM, the likely outcome would be termination.[22] In addition, eligible DG has benefitted from up to six years of further ACOT payments since the Authority's 2016 decision.

4.4 We are also confident that removing the obligation to make ACOT payments is unlikely to prompt any heightening of reliability risks,[23] including because:

(a) existing distributed generation is unlikely to cease operation when ACOT payments cease given ongoing revenue streams linked to nodal prices

(b) nodal prices provide a more efficient signal than ACOT payments for coordinating the operation of distributed generation (and other resources) – and the Authority is improving the effectiveness of nodal pricing through its real-time pricing project, which includes measures to remove barriers to distributed generation offering into the market (and therefore potentially setting prices)

(c) Transpower can contract with distributed generation directly if situations arise where this is an efficient alternative to grid investment.

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21 By grid reliability risk, we mean Transpower's ability to continue to meet the Grid Reliability Standards (GRS) across its network. Distributed generation may provide support to Transpower in meeting the GRS at points on its network, as an alternative to further transmission investment. We note that ACOT payments are not, by contrast, intended to assist with security of supply, ie, ensuring that in aggregate there is enough electricity generation to meet aggregate demand in any given trading period.

22 In 2016 we also noted that efficiency is enhanced if investors don't count on regulators allowing inefficient cashflows to continue.

23 To be clear, we do not consider that the existing ACOT lists mean that all distributed generators on those lists need to keep receiving ACOT payments for grid reliability to be maintained. The lists are based on an aggregated threshold assessment in relation to the Grid Reliability Standards (GRS) only. They do not indicate that all of the listed distributed generation is required to meet the GRS; or that ACOT payments to those distributed generators are required to meet the GRS.

(d) as a fall back, Transpower has options available including demand response, administrative load control, and revisiting its decision to not include a transitional congestion charge in the TPM.[24]

4.5 However, we recognise that it may be difficult for Transpower to confidently predict how changes in distributed generation behaviour could impact reliability and that contracting with distributed generation (if required) could take some time, including because:

(a) contracting for grid support from distributed generation is not a well-established, routine process

(b) other changes are occurring at the same time, including the new TPM coming into effect and growing investment (across demand and supply), and

(c) we expect Transpower would want to be reasonably satisfied that payments were necessary, not higher than required, efficient, and commercially viable.[25]

4.6 So, given the high cost of supply interruptions, we are seeking views on whether phasing out ACOT payments could be a prudent alternative.

Phasing out ACOT payments is a possible alternative

4.7 The aim of phasing out ACOT payments would be to provide time for Transpower to gauge and respond to any emerging reliability risk, including allowing Transpower and distributed generation providers to form contracts in the (reasonably unlikely) event that this is needed to sustain grid reliability.

4.8 A phase out would be akin to providing a short period of insurance cover, while ensuring the right incentives are in place during that period to reveal any previously masked grid support needs.

4.9 To be effective, we propose that any phase out profile should:

(a) be spread over two years, with a sizeable step down in year one – this strikes a balance between the ongoing cost to consumers of ACOT payments and the goal of providing time to observe behaviour change and form contracts. A sizeable step down in year one would help reveal behaviour change quickly

(b) be based on output averaged across 100 regional coincident peak trading periods – this would reduce the extent of change but does require a party (the Authority) to determine the peak period given Transpower would no longer be doing this as part of the TPM.[26]

4.10 The potential phase-out profile is shown in Table 2 below. Note that there is a lag between the capacity measurement period (CMP) when a generator's output is

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24 For further explanation see the Authority March 2020 information paper Peak charges under proposed TPM guidelines (ea.govt.nz), Concept Consulting's March 2021 paper Winter capacity margin: potential effect of possible changes to transmission pricing (ea.govt.nz), and Transpower's explanation of its decision to not include a transitional congestion charge in its proposed TPM: TPM Development Checkpoint 1 resubmission: Transitional Congestion Charge (transpower.co.nz).

25 For Transpower, commercial viability depends on whether payments can either be approved for recovery or meet an internal business case (which depends on the extent to which Transpower can retain the benefit of avoided investment costs).

26 We would apply the same rules as the current TPM in terms of capacity measurement period and regions across which coincident peaks are applied. It would be most efficient for the Authority to make this determination at the end of each capacity measurement period and advise impacted distributors.

measured, and the pricing year when payments are made, so any ACOT-related incentive to generate would end from 31 August 2024.

Table 2 ACOT phase-out profile

Pricing Year Ends	**March 2023**	**March 2024**	**March 2025**
CMP Ends	**August 2021**	**August 2022**	**August 2023**
Rate ($/kW)[1]	$96.89	$48.45	$24.22
Rate (%)	100%	50%	25%
Value ($m)[2]	$30m	$15m	$7.5m

Notes:

1 – payment to an eligible generator is based on the rate multiplied by that generator's average output across 100 regional coincident peak periods. There are four regions, and the 100 peaks for each region is determined after the capacity measurement. Output during the CMP ending August 2022 would be multiplied by the 2023/24 rate to determine payments for the pricing year ending 31 March 2023.

2 – value figures are indicative only.

4.11 We acknowledge that whether to include a phase out, and if so for how long, is ultimately a matter of judgement and we would welcome views that could help inform this judgement.

We prefer no phase-out

4.12 On balance, we do not favour the alternative of phasing out ACOT payments and prefer the position that the Code obligation to make ACOT payments ceases from April 2023. However, we would welcome submissions that assist with this judgement.

4.13 In our view, the arguments against phase out are compelling:

(a) stopping ACOT payments is unlikely to change distributed generator availability or behaviour in a way that would worsen grid reliability, particularly given nodal prices will still encourage generation at times and locations of transmission network stress – and the Authority's real-time pricing project enhancing the effectiveness of nodal pricing, including by removing barriers to small DG offering into the market[27]

(b) networks have already been able to begin observing reaction to removal of the 2023/24 interconnection charge, which would have been based on regional coincident peak demand (RCPD) recorded during the capacity measurement period ending August 2022

(c) phase out would cost distribution-connected consumers on the order of $22.5 million over two years – essentially for insurance of questionable worth

[27] We would be interested in receiving any alternative views, supported by evidence, regarding any distributed generation that, if it does not receive ACOT payments, will fail to operate at times when needed causing grid reliability problems,

(d) Transpower can contract for grid support services, or use tools such as load control or demand response, if needed to manage reliability risks arising from network congestion

(e) in 2020, Transpower “concluded that the tools available to the system operator and grid owner are sufficient controls to mitigate short term elevated congestion risk arising from removal of RCPD”[28] and opted not to propose a transitional congestion charge at that time. Transpower also retains the option to revisit the need for a transitional congestion charge if needed.

4.14 Weighing against these considerations is the fact that loss of supply is costly. For context:

(a) An economic cost of $20,000 per MWh of lost load is assumed in the Code.[29]

(b) Transpower reports an average unserved energy of 650 MWh per year.[30]

(c) $22.5 million is equivalent to 1,100 MWh per year of unserved energy (assuming an economic cost of $20,000 per MWh of lost load).

4.15 We have provided drafting at Appendix F that would give effect to the phase out alternative option (for consideration).

Consultation questions

Do you agree with the transition risks we have identified, and our assessment of them?

Do you think there are any other transition risks we should consider?

Do you have any information that would allow the Authority and Transpower to better assess the risk that removing the requirement to make ACOT payments could lead to changes in distributed generation behaviour that could impact reliability?

Do you have any comments on the design of the phase-out option?

Do you agree with our preference that ACOT payment obligations cease from April 2023 with no phase out?

28 Refer page 7 of Transpower’s 18 January 2021 submission the Electricity Authority: TPM Development Checkpoint 1 resubmission: Transitional Congestion Charge (transpower.co.nz).

29 Electricity Industry Participation Code, Schedule 12.2, clause 4(1)(a).

30 Average of two years ended June 2020 and June 2021, noting the year ended June 2019 is approximately 40 times larger (so we have treated it as an outlier). Note that this figure measures unserved energy across all transmission points of service, so may include energy served to end users through alternative points of supply. For unserved energy data, refer Tab G4 of Transpower’s 2020/21 information disclosures https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/ID%20Disclosures%202020-21.xlsx

5 Further work on network pricing for distributed generation

5.1 Subsequent to making our decision on ACOT provisions (that is the subject of this consultation), the Authority intends to provide guidance on any pass-through of transmission charges to distributed generation. The nature of this guidance will depend on this ACOT decision.

5.2 Longer-term we are planning to consider the wider set of incentives for investment in distributed generation to ensure they are efficient. This includes considering:

(a) nodal price signals

(b) Transpower's procurement of transmission alternatives

(c) the 'incremental cost' rule in the DGPPs

(d) neutrality between grid-connected and distributed generation, and between generation and other grid support technologies.

5.3 This work will consider whether additional price signals could be efficient, and how best to provide additional signals if warranted – noting that recoverable payments are not the only option.

5.4 We provide introductory context for this work in Appendix C, and invite comments on this material.

5.5 Below we briefly discuss the focus of planned work on the potential (if any) for additional signals to support efficient investment in grid support by third parties.

Future role of additional signals for grid support

5.6 In our 2016 ACOT decision, we said that our preference was for Transpower to procure any necessary grid support from post-2016 distributed generation directly. Transpower subsequently engaged with the sector on its processes for identifying and assessing opportunities for transmission alternatives.[31] In 2019 Transpower communicated four guiding principles, and committed to measures including:

(a) publishing a list that more clearly identifies where there may be opportunities for transmission alternatives

(b) enhancing its processes for maintaining a register of potential transmission alternative providers

(c) enhancing communication with potential providers

(d) maintaining its demand response programme as a cost-effective and targeted way of channelling payments to small providers.

5.7 In considering whether there is a future role for additional price signals for grid support technologies, we expect to, in consultation with the Commerce Commission:

(a) review the effectiveness of Transpower-led procurement, including considering:

(i) Transpower's progress since 2016

[31] Transpower's engagement process is recorded on its website at https://www.transpower.co.nz/keeping-you-connected/industry/transmission-alternatives

(ii) whether there are types of transmission investment for which Transpower would not be funded to procure alternatives (eg, for some connection asset investments)

(iii) whether Transpower's incentives are well aligned with discovering efficient payment levels (ie, neither too low nor too high).

(b) consider what principles should apply to any future regime for additional price signals. The Authority's (non-exhaustive) starting view is that any future price signals should:

(i) relate to actual transmission costs (not just charges)

(ii) not provide payments for investments or operation that would occur anyway (and not provide windfall gains)

(iii) work consistently with the incentives in the new TPM

(iv) work consistently with the incentives on Transpower under the Part 4 regime to find least cost solutions to its investment needs

(v) not create distortions in competitive markets, eg, incentivise distributed generation over grid-connected generation (or over other non-generation transmission alternatives, eg, storage, demand response)

(vi) not result in an increase to total consumer charges in the long run

(vii) be understandable, transparent, predictable, and workable – not encourage disputes over 'entitlements'.

5.8 We welcome your feedback on our proposed approach to this work, and on the principles set out above.

Consultation questions

Do you have any comments on the distributed generation pricing context material provided in Appendix C?

Do you have any comments on the Authority's plans for further work on whether there is a future role for additional price signals for grid support technologies?

6 Household bill impact

6.1 To provide context to our proposed changes, the Authority has estimated annual changes in household bills of a typical household served by each distributor.[32] [33] This is illustrated according to the impacts, from right to left in figure 2 below, of:

(a) introducing the new TPM,[34] assuming ACOT payments continue at the current rate[35]

(b) removing ACOT payments made at the current rate

(c) the combined effect of the above two factors

6.2 We consider it informative to illustrate the impacts of the new TPM and the removal of ACOT together because, if our preferred option is implemented, the requirement to pay ACOT will cease at the same time as transmission customers receive new charges under the new TPM.

6.3 We note this does not, and is not intended to, demonstrate the benefits of our proposal (our assessment of costs and benefits of our proposal is provided in Section 7).

6.4 The household bill impact of introducing a new TPM ranges from -$37 to $177 per year depending on which distribution network the household is connected to.[36]

6.5 The impact of removing ACOT payments ranges from $0 to -$72 per year, reflecting the total of ACOT payments by each distributor compared to the size of its customer base.

6.6 The household impact analysis is indicative only, but key insights are:

(a) only a subset of distributors recover ACOT payments from their consumers, and materiality varies considerably across the subset

(b) for some impacted distributors, removing ACOT recoveries could reduce household bills by as much as 2-3%.

6.7 The total change in household bills ranges from -$44 to $177 per year.

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32 We estimate the changes in charges in $/kWh terms for the typical household, and then compare that to a typical household's total electricity bill. Our estimate relies on MBIE's modelling of the national average household (based on total national electricity sales, and total national household consumption). For 2022, the average household consumed 7,261kWh of electricity per annum, at a cost of $0.30/kWh, with an average bill of $2,194 per annum, GST inclusive. Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statisticsand-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring/.

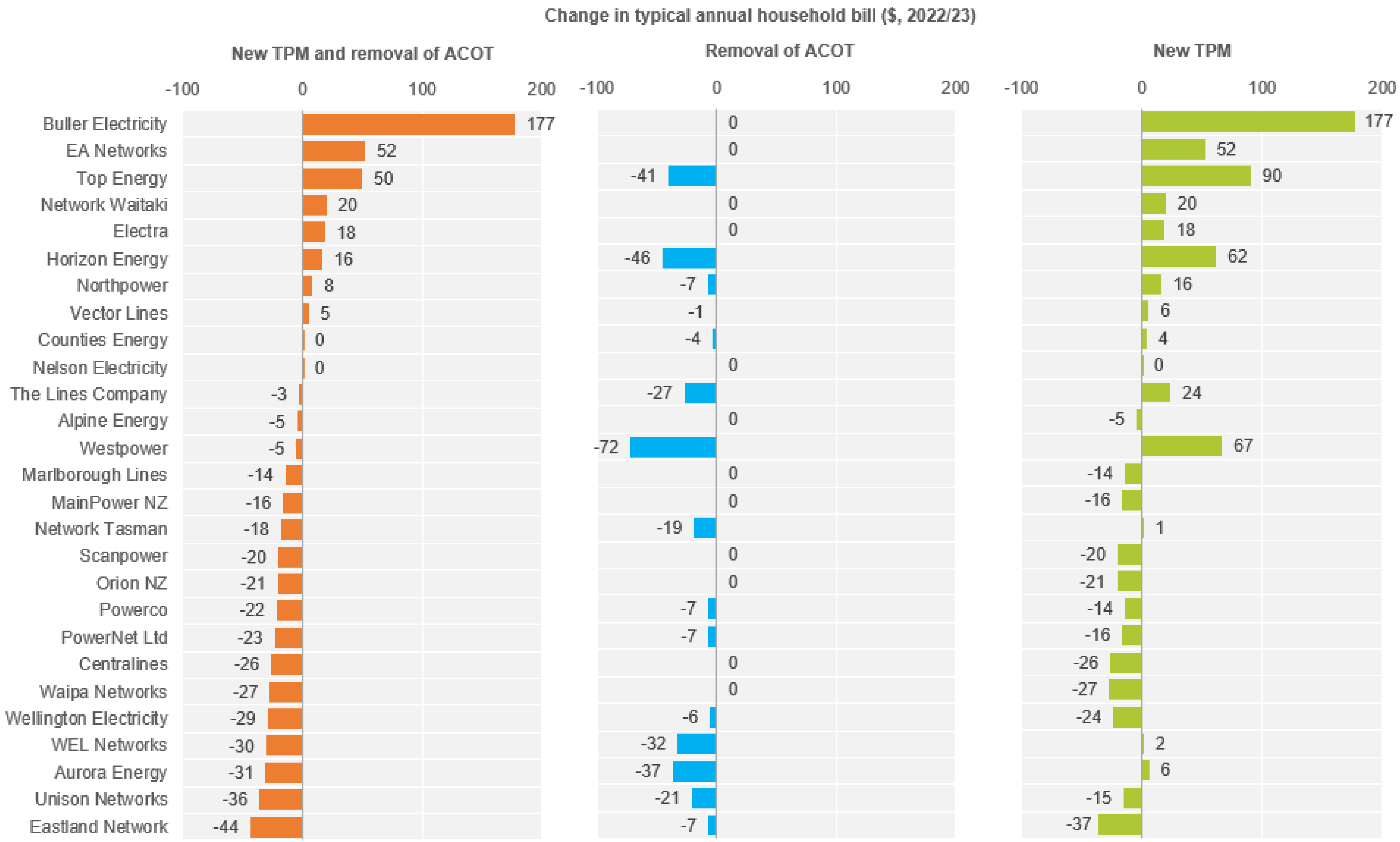
33 Pass-through of transmission charges from a distributor to customers (in general, retailers) depends on the distributors' pricing approach. The Authority's modelling assumes retailers will translate changes in transmission charges into $ changes per unit of energy and pass charges on to their customers accordingly. This assumes workable competition in the residential, commercial, and industrial electricity retail markets

34 TPM charges are based on Transpower's 18 August 2022 update of indicative pricing for the 2022/23 pricing year.

35 ACOT payments are based on information disclosures for the year ended 31 March 2021. Source: EDB information disclosures, Schedule 3, https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/information-disclosed-by-electricity-distributors

36 For further context on indicative prices refer to Transpower, Pricing year 2022/23 Indicative Prices www.transpower.co.nz/sites/default/files/uncontrolled_docs/TPM%20Indicative%20Prices%20August.pdf For more discussion of variations in household bills, which translate these indicative prices into household bill impacts refer to the 2021 TPM consultation paper, paragraphs 12.44 to 12.58, noting that these figures reflect Transpower's 2021/22 indicative pricing. www.ea.govt.nz/assets/dms-assets/29/Proposed-Transmission-Pricing-Methodology-Consultation-paper-v2.pdf

Figure 2 Impact on a typical household of New TPM and removal of ACOT



7 Regulatory statement for the proposed amendments

7.1 We have proposed two options for Code amendments:

(a) Option 1 – clarify that ACOT payments are not required from April 2023 (as described in section 3 and Appendix EAppendix F)

(b) Option 2 – as above, but phase ACOT payments out over two years (as described in section 4 and Appendix F)

7.2 Our preference is Option 1.

Objective of the proposed amendments

7.3 The objectives of the proposed amendments are described in Section 3 for Option 1, and in Section 4 for Option 2.

The proposed amendments

7.4 The Authority proposes, subject to consultation, to amend Part 1 and Schedule 6.4 of the Code as described in the preceding chapters of this paper and as laid out in Appendix F.

The preferred amendments' benefits are expected to outweigh its costs

7.5 The Authority has assessed the benefits and costs of the proposed Code amendments against a counterfactual of no Code amendment. We expect Option 1 will deliver a net benefit, whereas Option 2 may not.

7.6 Option 2 could potentially deliver a greater benefit than Option 1 if the benefits of avoiding a possible deterioration in grid reliability by phasing payments out exceed the costs associated with reduced efficiency and competition. However, we consider the risk of a deterioration in grid reliability under Option 1 (as well as in the counterfactual) to be low and therefore consider Option 1 is likely to deliver greater net benefits than Option 2.

7.7 The benefits of our proposed amendments are assessed against each limb of our statutory objective – competition, reliability, and efficiency.

Counterfactual

7.8 We have assessed the options against a counterfactual of no change to the Code[37]. The outcomes of the counterfactual may include:

(a) dispute costs –we expect most participants would reach the view that ACOT payments are no longer required even without the Code change, and in some instances reaching this position may not involve material costs (contracts would expire). However, we recognise that there is potential for disputes (potentially at significant cost) over whether ACOT is payable and the form of ACOT payments that may be appropriate when the new TPM starts[38]

(b) inefficient payments directly leading to higher costs to consumers and subsidies to distributed generation – some participants might reach a view that some form of

[37] However, the new TPM would of course still come into effect under the counterfactual as that Code change has already been made

[38] In this instance we are not considering dispute costs associated with distributors seeking to exit 'evergreen' contracts for making ACOT payments (enduring contracts that do not alter despite the requirement to pay ACOT being removed from the Code). These dispute costs exist in the factual and counterfactual.

ACOT payments linked to allocator updates or future investments may be warranted:

(i) payments linked to allocator updates would be inefficient – as set out in section 3, such an approach could result in ACOT payments funding unproductive charge avoidance and potentially undermining nodal pricing signals

(ii) payments linked to future investments would have a high likelihood of being inefficient – again, as set out in section 3, this could either result in unnecessary payments (for actions that would have occurred anyway) or funding of a less efficient outcome (than relying on nodal prices and Transpower's incentives to find least-cost solutions)

(c) The extent of these inefficient payments would depend upon the extent to which distributors continued to make ACOT payments in the absence of a Code change.

7.9 There is a possibility that some payments that might continue under the counterfactual could be efficient as they may happen to be required to support distributed generation that is operating in a way that avoids the need for further transmission investment and would otherwise not do so, and the cost of the payments may be lower than the transmission cost being avoided by their operation. Stopping these payments may lead to higher transmission costs if that distributed generation ceases to perform that function. However, this appears unlikely, noting that nodal prices will signal the value of generation and so encourage distributed generation to operate when required, and Transpower could pay providers of transmission alternatives, including distributed generators, directly if that provides a lower cost (or more feasible) solution than investing in the grid.[39]

7.10 In the counterfactual, there would also be costs associated with the ongoing administration of any ACOT payments which distributors considered should be made but we expect these would be modest.

7.11 There may also be a short-term risk of deterioration in grid reliability under the counterfactual associated with ACOT payments ceasing or reducing. As with the reliability risk discussed in section 4 in the context of ceasing payments under Option 1, we consider a short-term deterioration in grid reliability is unlikely because distributed generation will continue to have incentives to operate in response to nodal prices and because Transpower retains options to mitigate reliability risks directly if required.

7.12 We also consider, to the extent there is a short-term risk of deterioration in grid reliability, it is unlikely that any continued ACOT payments would significantly limit this risk. While we consider some distributors might reach a view that some payments relating to allocator-based charges and charges for future investments are warranted:

(a) Those payments are unlikely to be well matched to inducing the necessary generation response to meet the specific reliability needs that Transpower is seeking to address

(b) The payments are unlikely to add much to the stronger signals arising from nodal pricing in the wholesale electricity market: nodal prices likely provide sufficient

[39] Note that the Authority is considering further work on whether distributed generation faces efficient incentives to invest. As such, any negative effects under this aspect of the counterfactual may be short-lived.

incentive by themselves for the DG to operate when required under the counterfactual and both proposed options.

Efficiency

7.13 Option 1, which would clarify that ACOT payments are not required from April 2023, is expected to significantly reduce:

(a) costs associated with resolving any disputes over what, if any, ACOT payments might be appropriate when the new TPM starts.

(b) the scope for inefficient payments.[40]

7.14 The quantum of the reduction in dispute costs is not straightforward to assess and would require, among other things, detailed information on contractual arrangements. We welcome any evidence that illustrates the expected reduction in these costs under Option 1 and 2.

7.15 Inefficiencies relating to inefficient ACOT payments in the counterfactual and in Option 2 during the phase out period, and which would be avoided under Option 1, include:

(a) additional operational costs of eligible distributed generation compared to other generation or flexibility services that would operate instead (if distributed generation receives payments that are linked to usage this could result in them offering into the market at a price below their operational cost and therefore being dispatched out of merit order).

(b) allocative inefficiencies due to end consumers inefficiently curtailing electricity demand (they may either not use energy or may use a more expensive energy source, eg, gas for their hot water heating, or petrol for their electric vehicle) as a result of receiving higher bills than they otherwise would

(c) dynamic inefficiencies as the suppression of nodal price signals due to distributed generation eligible for ACOT payments being preferred over other, more efficient generation (ie, operating out of merit order, as described in (a) above) which may result in lower investment in productive efficiency improvements over time, such as the development of flexibility services in the New Zealand context.

7.16 The benefits from reductions in the above inefficient payments under Option 1 are related to the size of the payments, but are also uncertain. For context:

(a) In 2021, 15 distributors made ACOT payments totalling approximately $35 million.[41]

(b) We expect any surviving payments (efficient or inefficient) under the counterfactual would be substantially lower, and even lower under Option 1.

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40 Note that the amendments remove the regulatory obligation to make ACOT payments. It is possible some contractual obligations may survive.

41 Source: EDB information disclosures, Schedule 3 https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/information-disclosed-by-electricity-distributors.

(c) The efficiency benefit – from reduced inefficient ACOT payments – under Option 1 is related to[42] the difference between the remaining ACOT payments under the counterfactual, and the remaining ACOT payments under Option 1[43].

7.17 Option 1 could potentially incur a cost (or disbenefit) associated with stopping efficient payments. However, we consider this doubtful as we expect the likelihood of there being efficient payments which would continue in the counterfactual but not under Option 1 is low (as discussed in counterfactual section above)

7.18 We note also that the Authority is planning further work on whether there is any case for additional signals to grid support technologies in future.

7.19 Option 2 would also reduce dispute costs by a similar amount as Option 1. Distributors and distributed generators would however incur the administration costs associated with paying ACOT for two more years but these are expected to be modest.

7.20 After phase out, the reduction in distortion due to inefficient ACOT payments under Option 2 is the same as under Option 1.

7.21 However, in the near term Option 2 would likely introduce inefficiencies by providing for, most likely, a significantly higher total amount of inefficient ACOT payments to continue during the phase out period than under the counterfactual.[44] The size of increased inefficiencies would be related to the difference in ACOT payments between Option 2 and the counterfactual.

7.22 It is unclear, however, how option 2 compares to the counterfactual in terms of the total reduction in inefficiencies over time (before and after the phase out) – this would depend on the composition of approaches taken to ACOT in the counterfactual.

Competition

7.23 We consider that Option 1 would create a more level playing field between competing technologies and participants, by removing some of the potential distortions to competition which might arise under the counterfactual and Option 2.

7.24 Specifically ,the counterfactual and Option 2 in the short term could both involve continuing ACOT payments. This is likely to have an adverse impact on competition because they create or exacerbate differences in revenue between:

(a) grid-connected vs. distributed generation

(b) distributed generation vs. other providers of grid support services

(c) eligible distributed generation and other distributed generation.

7.25 The differences in revenue could have an adverse impact on competition between generators for dispatch, and for entry or expansion. Suppression of nodal price signals to new entrants due to distributed generation operating out of merit order could exacerbate this further. These issues would not arise under Option 1.

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42 The efficiency benefits of Option 1 do not equate to the difference in the amount of payments between Option 1 and the counterfactual as these are largely wealth transfers from consumers to distributed generators. However, the size of efficiency benefits is likely to be higher the higher the difference in inefficient ACOT payments.

43 Some ACOT payments may remain under Option 1 due to ‘evergreen’ contracts.

44 We note that while our analysis does not explicitly consider wealth transfers between distributed generators and consumers, Option 2 involves a temporary wealth transfer from consumers to distributed generators that would not occur under Option 1, and would likely occur to a lesser extent under the counterfactual.

7.26 As between Option 2 and the counterfactual, on balance over time, it is not clear whether Option 2 would have a net competition benefit compared to the counterfactual. In the near term, there is likely to be a significant disbenefit due to higher ACOT payments, but following the phase out period for there is likely to be a benefit from increased competition compared to the counterfactual.

Reliability

7.27 As described in section 4, we are mindful of the potential for some risk of deterioration in grid reliability if ACOT payments largely[45] ceased under Option 1.

7.28 However, we do not consider reliability is likely to be significantly impacted by Option 1 compared to the counterfactual, because we consider there to be a relatively equivalent low risk of deterioration in reliability in the counterfactual (as described in counterfactual section above). While there may be some continuation of ACOT payments in the counterfactual, these are likely to not be well targeted to induce an effective response to any given reliability issue;[46] therefore, any mitigation of reliability risks due to these payments compared to Option 1 would be small.

7.29 However, we are considering Option 2 as a possible means for mitigating residual risk (if any) to reliability. Option 2 may improve confidence that reliability will not worsen by providing a longer period in which Transpower can assess and respond to emerging issues (if any), eg, by investing in grid assets or contracting with specific DG if needed to support grid reliability.

Net benefits and Option 1 and Option 2

7.30 We expect Option 1 will provide net benefits compared with the counterfactual as we expect it to deliver benefits associated with both efficiency and competition, and that it is unlikely to impact reliability.

7.31 It is unclear whether Option 2 would provide net benefits:

(a) The total benefits associated with efficiency and competition over time (noting there are likely to be disbenefits during, and benefits following, the phase out period) depend on the approaches to ACOT, and therefore the extent of payments long-term, in the counterfactual

(b) Option 2 potentially provides reliability benefits by insuring against the risk of reduced reliability over the next two years.

7.32 Through consultation, we are seeking to better understand the potential reliability benefits of Option 2. This will help us determine whether our assessment of Option 1 being more beneficial than Option 2 is robust.

7.33 Option 2 would deliver a greater benefit than Option 1 only if:

(a) phasing payments out would, by buying Transpower time to assess and respond to emerging issues, avoid a deterioration in grid reliability during the phase-out period that would occur under Option 1, and

(b) if this reliability benefit exceeds the efficiency and competition disbenefits associated with ACOT payments continuing during the phase out period.

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45 Note that while the proposed Code amendments remove the regulatory obligation to make ACOT payments, it is possible some contractual obligations may survive.

46 Cf, the nodal pricing signals that are likely provide sufficient incentive for the DG to operate when required under all scenarios (counterfactual and both options).

7.34 Our current view is that Option 2 is unlikely to provide greater benefit than Option 1, as the reliability benefit of the transitional payments provided for in Option 2 is likely to be low.

7.35 We are confident that Option 1 delivers net benefits,[47] and consider that whether Option 2 would provide net benefits is uncertain. However, we invite stakeholder submissions on both of these assessments.

Summary

7.36 The table below summarises the benefits from both options associated with competition, reliability, and efficient operation of the industry, and the overall long-term benefits to consumers. It also compares Option 1 and Option 2.

	Option 1	Option 2
Efficient operation of the industry	Promotes efficient operation by avoiding legal and admin costs and preventing inefficient approaches to ACOT payments	Either promotes or hinders efficient operation of the industry depending on make-up of approaches to ACOT payments in the counterfactual
Competition	Promotes competition to the extent it prevents ACOT payments subsidising some generation over others	Either promotes or hinders competition depending on make-up of approaches to ACOT payments in the counterfactual
Reliability	Has no impact on reliability	Potentially improves reliability
Overall (long-term benefits to consumers)	Net benefits associated with improved competition and efficient operation.	Depends on counterfactual approach to ACOT
Option 1 vs Option 2	We are open to views on whether Option 2 may be superior to Option 1. Our current view is Option 2 would deliver a greater benefit than Option 1 only if phasing payments out would avoid a substantial deterioration in grid reliability in the phase-out period.	

47 As discussed in Chapter 3, Option 1 would promote efficiency – the risk that the cost of inefficient ACOT payments will be recovered from consumers will be removed, and administrative costs associated with the transition to a new TPM will be reduced. And it would promote competition – removing ACOT payment obligations levels the playing field between pre-2017 and new DG, and between DG and other transmission alternative providers (including grid-connected generation, and other technologies that provide flexibility).

Alternative means of achieving the objective

7.37 As discussed above, the Authority has identified Option 2 as an alternative to our preferred Option 1.

7.38 Our current assessment (and subject to consultation) is that this alternative is not as effective in meeting the Authority's statutory objective.

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

7.39 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.

7.40 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 expected to have a material impact on competition in the electricity market
(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 are expected to result in more efficient operation by distributors and distributed generation.
(d) the performance by the Authority of its functions	The proposed amendments are consistent with the Authority's function to make the Electricity Industry Participation Code.
(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

7.41 When considering Code amendments, we are required by our Consultation Charter[48] 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

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

Principle	Comment
	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 above.
3. Net benefits are quantified	Net benefits are not able to be accurately quantified, so the Authority's assessment is qualitative.
4. Preference for small-scale 'trial and error' options	Not applicable. Principles 4-8 apply when the CBA of Code amendment options demonstrates a positive net benefit relative to the counterfactual, but is inconclusive about which is the best option. Principles 4-8 do not apply in this case as the CBA supports the proposed option.
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	Not applicable.
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 Background to DG access arrangements and reform process

A.1 We set out below the rationale for the introduction of the ACOT regime through the DGPPs, and the reform process that started in 2015.

A.2 The DGPPs were originally developed as part of a set of distributed generation access regulations passed in 2007.[49] The regulations were intended to encourage investment in small scale electricity generation by making it easier for distributed generation developers to arrange connection of their generation, including by:

(a) providing default connection contracts

(b) prescribing aspects of the connection process, including timeframe and fee limits

(c) requiring application of favourable (to distributed generators) distributed generation pricing principles.

A.3 The Minister at the time noted that because most distributed generation was renewable, the regulations would help New Zealand avoid greenhouse gas emissions otherwise produced by generation using fossil fuels.[50] The regulations transferred into Part 6 of the Code when the Authority was formed in 2010.

A.4 The regulations provide different default contracts, fees, and timelines for small (<10kW) and larger distributed generation but have common pricing principles across all distributed generation. Notably:

(a) there is no upper limit of the size of generators covered by Part 6. The regulations apply to very large, distributed generation that could feasibly opt for grid connection, and the pricing arrangements are relevant to prudent discount agreements negotiated between Transpower and grid-connected generators[51]

(i) the regulations are technology neutral across generation types (eg, not limited to renewable generation) but not technology neutral across types of distributed energy resources (ie, they only apply to generation and not to batteries or other flexibility providers)

(ii) very small generation (eg, most rooftop solar) is typically embedded behind load and may not interact with Part 6

(iii) we understand that distributors typically don't make ACOT payments to generators smaller than 100 kW.[52]

2015/2016 review of DGPPs

A.5 In July 2015 the Authority started a review of the DGPPs to ensure they met the Authority's statutory objective "to promote competition in, reliable supply by, and the

49 Electricity Governance (Connection of Distributed Generation) Regulations 2007 (SR 2007/219) (as at 01 November 2010) Contents – New Zealand Legislation.

50 Draft regulations to help distributed generation reduce greenhouse gas emissions | Beehive.govt.nz.

51 Generators can negotiate discounted transmission charges if they can demonstrate that it would be commercially attractive (but inefficient) for them to bypass transmission charges by connecting to a distribution network. Distributed generation pricing influences eligibility and the size of the discount.

52 At current rates, a 100kW generator could earn up to $9,689 per year from avoided interconnection charges.

efficient operation of, the electricity industry for the long-term benefit of consumers".[53] In this review, the Authority identified two key issues with the DGPPs:

(a) the connection service issue – the DGPPs require distributors to charge owners of distributed generation no more than the incremental cost for connection and distribution services – ie, to make zero contribution to common costs. This does not promote efficiency

(b) the ACOT issue – the provisions in the DGPPs relating to transmission have led to distributors paying generators for avoided transmission charges. These payments inefficiently influence distributed generation operation and investment.[54]

A.6 In a May 2016 consultation paper, the Authority proposed to remove the DGPPs from Part 6 of the Code to address both issues. The Authority considered that the DGPPs were not needed in addition to the Authority's voluntary distribution pricing principles. The Authority considered that removing the DGPPs would address the connection services issue because distributors would no longer be required (by the DGPPs) to treat distributed generation on a preferred basis when they set charges for distribution services. It would also address the ACOT issue because it would leave Transpower solely responsible for obtaining and paying for transmission-substitute services that distributed generation provides.

A.7 The Authority identified (in the May 2016 consultation paper) three alternatives to removing the DGPPs. These alternatives involved amending, rather than removing, the DGPPs. Under each alternative, the connection services issue would be addressed by amending the DGPPs so that charges must be in the range from incremental cost to standalone cost of providing those services. However, each alternative dealt with the ACOT issue differently:

(a) Alternative 1 – transmission costs or charges excluded from the definition of "incremental cost" in the DGPPs

(b) Alternative 2 – ACOT payments by distributors banned

(c) Alternative 3 – only ACOT payments approved by Transpower could be made (with Transpower approving payments only if they would efficiently defer or reduce transmission investment costs).

A.8 The Authority considered that removing the DGPPs or implementing any of the three alternatives would provide broadly similar ACOT-related benefits and costs relative to the status quo. The Authority preferred removing the DGPPs over the alternatives because it was the most consistent with the 'tie breaker' Code amendment principles.[55] In particular, removing the DGPPs:

(a) should better promote competition between distributed generation and grid-connected generation,

53 The statutory objective is set out in section 15 of the Electricity Industry Act 2010: Electricity Industry Act 2010 No 116 (as at 28 October 2021), Public Act – New Zealand Legislation.

54 Page B, https://www.ea.govt.nz/assets/dms-assets/20/20718Consultation-paper-Review-of-distributed-generation-pricing-principles.pdf.

55 Page M, https://www.ea.govt.nz/assets/dms-assets/20/20718Consultation-paper-Review-of-distributed-generation-pricing-principles.pdf.

(b) would provide distributors with greater flexibility to adopt more efficient pricing structures, and

(c) is less prescriptive than the other options.[56]

A.9 After considering issues raised in submissions, the Authority pulled back from its initial proposal, noting the risk that removing the DGPPs from the Code may not promote the Authority's statutory objective and rather could have a negative impact on efficiency and reliability. This was because removing the DGPPs could:

(a) allow distributors to use their monopoly power to overcharge distributed generation for connection services

(b) exacerbate the risk that distributors underpay avoided costs of distribution (ACOD).

A.10 In addition, the Authority considered that removing the DGPPs may not ensure competitive neutrality between distributed generation and grid-connected generators (and other technologies). The Authority considered it would not be possible to resolve this issue until the reviews of TPM and distribution pricing had been progressed further.[57]

(a) in December 2016 the Authority decided to:

(i) defer consideration of the connection services issue

(ii) respond to the ACOT issue by adjusting the DGPPs to (a) ensure that distributors would not pay ACOT for any post-2016 distributed generation; and (b) limit ACOT payments, to some extent, to existing recipients. The Code amendment required Transpower to identify which distributed generation was required for Transpower to meet the Grid Reliability Standards and advise the Authority of its findings. The Authority would then decide, based on Transpower's advice and following consultation, which existing distributed generation should receive ACOT payments under the regulated terms.

A.11 The Authority decided not to alter the rate ($ per kWh) for ACOT payments at the time noting that "…this is a transitional arrangement, and we expect arrangements to be refined at a future point so that ACOT payments do not exceed the transmission benefits being provided by distributed generation."

Lists of distributed generation eligible for ACOT payments

A.12 In 2017 and 2018, Transpower provided the Authority with lists of distributed generation that had been identified based on a threshold assessment in relation to the Grid Reliability Standards in each of the lower South Island (LSI), upper South Island (USI), lower North Island (LNI), and upper North Island (UNI). The Authority then consulted on lists of distributed generation eligible for ACOT before making a final decision on lists for each of the four regions. In total there were 7,590 generation installations on the list with an overall capacity of 1,033 MW.[58]

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[56] pp58-59, https://www.ea.govt.nz/assets/dms-assets/20/20718Consultation-paper-Review-of-distributed-generation-pricing-principles.pdf.

[57] P10, https://www.ea.govt.nz/assets/dms-assets/21/21514DGPP-decisions-and-reasons-paper-complete.pdf.

[58] This included 661 generation installations in the LSI, 651 in the USI, 2,582 in the LNI, and 3,696 in the UNI. The lists are available here: Electricity Authority - EMI (market statistics and tools) (ea.govt.nz)

Consideration of changes to the ACOT regime in the TPM Issues Paper

A.13 The Authority consulted on possible changes to the ACOT regime as part of our TPM Issues Paper released in July 2019.[59] The changes were intended to clarify that distributors are:

(a) required to make ACOT payments to owners of distributed generation in respect of transitional peak (later transitional congestion) and kVAr charges (if these are included in the TPM)

(b) not required to make ACOT payments to owners of distributed generation in respect of benefit-based charges, residual charges and/or connection charges.

A.14 We noted in the paper that the TPM guidelines would change the basis for ACOT payments. ACOT payments have been based on reductions in distributors' RCPD changes due to the operation of distributed generation, but under the proposed TPM guidelines distributors would no longer pay RCPD charges. Instead, they would pay:

(a) charges with largely fixed allocations (the benefit-based charge, residual charge, and connection charge) that are intended to avoid influencing use of the grid

(b) variable charges (the transitional peak charge and kVAr charge) that are intended to influence use of the grid.

A.15 In the TPM Issues Paper we considered that if variable charges are included in the TPM it may be efficient for the price signals they send to be passed on to distributed generation, if that encouraged efficient operation by distributed generation that could reduce variable costs. ACOT payments based on reductions in distributors' transitional peak and kVAr charges might allow this.

A.16 We also noted that we were considering making further changes to Part 6 of the Code so that all distributed generation would be treated alike. This would mean that there would be no distinction between distributed generation based on the date of installation and that the lists of ACOT-eligible distributed generation published by the Authority would not be needed.

A.17 We considered, in the 2019 TPM Issues Paper, that it would not be consistent with our statutory objective for ACOT payments to be made for avoiding transmission charges with a largely fixed allocation. This was because ACOT payments based on reductions in fixed charges would not encourage efficient operation by distributed generation, would not provide incentives for distributed generation to operate at particular times, and would not reduce variable transmission costs. We were concerned that the wording in Schedule 6.4 of the Code did not make it clear that ACOT would not be payable in respect to fixed charges and therefore were considering an amendment to Schedule 6.4 to remedy this.

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59 Appendix F, https://www.ea.govt.nz/assets/dms-assets/25/25466TPM-Issues-Paper-30-July-2019-full-document.pdf.

Appendix B ACOT consultation as part of TPM reform

B.1 Post the Authority's 2016 decision, issues relating to ACOT payments have arisen in the context of the Authority's TPM consultation processes.

B.2 As discussed in Appendix A, the 2019 transmission pricing review issues paper consultation document included a proposal that Part 6 of the Code be amended to clarify that distributors:

(a) are required to make ACOT payments in respect of avoided variable charges (ie, transitional peak and kVAr charges if these are included)

(b) should not make ACOT payments in respect of fixed charges (ie, benefit-based, residual or connection charges).

B.3 ACOT was out of scope for the 2021 proposed TPM consultation paper, however it was referred to occasionally (and usually indirectly) in some submissions.

B.4 Several submitters across both consultations supported the amendment to remove ACOT payments for fixed transmission charges (the change at B.2(b) above) because:

(a) There is a need to ensure that the ACOT provisions in the Code align with the new TPM following the removal of the inefficient RCPD charge.[60] Meridian noted that "the very basis for [ACOT] payments is peak based RCPD charges which will not feature in the proposed TPM".

(b) The change would treat all DG alike, regardless of when it was installed and whether it is on the list of eligible generation.[61] Powerco noted that this Code change would "allow distributed generation to compete on a level playing field with other forms of generation."

(c) Distribution customers would benefit from lower charges as distributors would no longer be making ACOT payments to DG. This is particularly important in regions where TPM charges would otherwise increase or in lower socio-economic areas.[62] In their 2021 submission, The Lines Company noted that "customer affordability is of the highest concern to TLC and a situation where there is an increase in transmission charges as per the proposal and where any form of ACOT payment is deemed 'efficient' is not acceptable to TLC and our consumers."

B.5 However, some submitters did not support allowing ACOT payments to continue for variable transmission charges (the change at B.2(a) above), because:

(a) Such clarification may be unnecessary if no variable charges are included in the TPM (as is currently the case).[63]

(b) There was concern that the TPM would include a peak charge (which would "water down" the TPM) for transitional purposes due to concerns about changing the ACOT regime.[64] However, as the decision to change the TPM has been finalised, this is not a current concern.

60 Meridian and Powerco in their 2019 submissions.

61 Meridian and Powerco in their 2019 submissions.

62 Electra in its 2019 submission and The Lines Company in its 2019 and 2021 submissions.

63 Meridian in its 2019 submission.

64 Meridian in its 2019 submission.

(c) WEL Networks submitted that ACOT payments based on variable charges should only apply to dispatchable DG, because “any benefit non-dispatchable or non-firm generation provide by reducing variable transmission charges can only be considered incidental at best.”[65]

(d) In the context of improving the existing TPM through incremental changes, Contact advocated for “the complete removal of Avoided Cost of Transmission payments that incentivise embedded generation and effectively transfer transmission costs onto other users”.[66]

B.6 Other submissions raised additional points on the ACOT regime regarding the following matters without expressly supporting or opposing either amendment:

(a) **Section 54Q of the Commerce Act 1986** – this section requires the Commerce Commission to incentivise distributors to “invest in energy efficiency and demand side management, and to reduce energy losses”. Some submitters argued that ACOT payments were “the only significant arrangement that helps address the Commerce Act’s s54Q requirement”. [67] ETNZ requested clarity on the relative value to different parties of removing ACOT payments, as well as further consultation on how ACOT payments could be modified to ensure greater consumer benefit and support the objectives of s54Q.

(b) **Amended peak losses equation –** Nova submitted that if their additional peak losses equation was introduced in SPD (a recommendation they made in respect of improving nodal prices), then DG would receive sufficient incentives from nodal prices so ACOT payments would not be required.[68]

(c) **Bilateral agreements** – some submitters noted the existence of bilateral agreements between distributors and DG providers relating to ACOT payments.[69] Horizon Networks submitted that “the viability of the Prudent Discount Agreement and corresponding ACOT agreement is compromised with the proposed Transmission Pricing Methodology, as this represents a clear amendment in the Transmission Rules.” WEL Networks submitted that it was obliged to make ACOT payments under such an agreement so long as regulations “do not prevent us from doing so” and therefore suggested that the amendments to Part 6 be more explicitly worded to “ensure that distributors are not required to continue payments by bilateral arrangements and that consumers receive the maximum benefit from the proposed TPM”. On the other hand, Transpower (which did not otherwise take a view on ACOT changes) noted that removing a regulatory right to ACOT payments is not the same as stopping ACOT payments where they have been agreed in a contract.

(d) **DGPPs may ignore ACOT completely** – Powerco questioned whether the DGPPs need to reference ACOT at all. Powerco noted, “A neutrality principle suggests no individual technology (like DG) should get different treatment to other technologies that provide the same service (if they do)”, and argued that ACOT

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65 WEL Networks in its 2019 submission.

66 Contact in its 2021 cross submission.

67 ETNZ in its 2019 submission and IEGA in its 2019 cross submission.

68 Nova in its 2019 submission.

69 WEL Networks in its 2019 submission, and Horizon Networks and Transpower in their 2021 submissions.

payments could mean “consumers on a distribution network pay for DG services which extend beyond the network (as reflected by the design of the prices)”.[70]

(e) **Procedural issues** – Some submitters were conscious of the time constraints in the TPM development process.[71] MEUG requested reasonable notice and time for submissions on this issue, and Horizon Networks argued that there would not be sufficient time for a full consultation before the new TPM came into place.

70 Powerco in its 2019 submission.

71 Horizon Networks and MEUG in their 2021 submissions and Contact in its 2021 cross submission.

Appendix C Distributed generation pricing context

C.1 The following sections provide background information on the context for distributed generation pricing, including other relevant regulatory incentives and regimes. This context is relevant to the Authority's longer-term work on the reform of distributed generation pricing.

Pricing design operates alongside revenue control

C.2 The Commerce Commission regulates electricity lines services under Part 4 of the Commerce Act 1986. This includes:

(a) information disclosure obligations for all businesses supplying electricity lines services – this includes Transpower and all distributors

(b) price-quality regulation for Transpower and non-exempt distributors[72] – in practice, this involves setting cost-based revenue caps.

C.3 The Commerce Commission aims to promote the long-term benefit of consumers by, among other things, ensuring suppliers have incentives to innovate, to invest, and to improve efficiency.[73]

C.4 Distributed generation is relevant to these objectives because it can potentially (in certain circumstances) provide an efficient substitute for investment in network capacity. Ideally, regulatory arrangements would:

(a) be fully effective at encouraging lines companies to optimise between investing in network capacity and providing funding to distributed generation (or other suppliers of flexibility services)

(b) be effective across the supply chain, so that funding would flow to distributed generation (and other flexibility services) whether it is substituting for distribution or transmission network investment (or both)

(c) ensure the benefits of efficiency gains were shared with consumers through lower prices.

C.5 The goal of optimising between network and generation investment is also relevant to network pricing arrangements (which the Authority regulates). As such, there are effectively three pathways through which optimisation can be promoted:

(a) pricing design – well-designed pricing encourages efficient coordination of network usage and investment

(b) expenditure incentives – economic regulation can be designed to incentivise networks to adopt least-cost solutions – ie, so firms will have a viable business case for funding generation services if that is lower-cost than building network capacity

(c) recoverable costs – if pricing design and expenditure incentives together result in inefficiently weak support for generation investment, allowing networks to treat payments to generators as a recoverable cost could potentially be efficient.

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72 Consumer-owned electricity distribution businesses that meet certain criteria are exempt from price-quality regulation.

73 Refer s52A of the Commerce Act 1986 for a full description of the purpose of the Part 4 regulation.

C.6 This means that ACOT arrangements should be cognisant of pricing and revenue control arrangements for transmission and distribution services.

Transmission pricing arrangements are being reformed

C.7 Several aspects of transmission pricing design are being reformed across three related projects:

(a) a new, more efficient TPM will be in place from April 2023

(b) incremental improvements to nodal pricing are being made through the Authority's real-time pricing project

(c) the Authority is consulting on arrangements for rebating revenue from the transport component of nodal prices to transmission customers.[74]

C.8 The TPM currently in place inefficiently signals transmission costs, including by:

(a) allocating all HVDC costs to South Island generators for recovery through an injection-based charge,[75] which discourages grid injection in the South Island

(b) pooling interconnection costs and spreading them across the country, which dampens incentives to optimise investment (including between generation and transmission)

(c) recovering interconnection costs through a peak demand charge,[76] which discourages offtake during peak, and encourages cost shifting behaviour (making investments specifically to shift more transmission charge burden to other customers).

C.9 The new TPM replaces the current HVDC and interconnection charges with benefit-based charges (BBCs).[77] BBCs:

(a) use fixed allocations based on one-off assessments of the expected benefits of new transmission investments

(b) recover those allocations via fixed charges designed to avoid influencing usage.

C.10 Remaining (residual) costs will be recovered via a charge that is also designed to avoid influencing usage, while using historical gross demand as a proxy for size (and hence ability to pay).

C.11 Key outcomes of this include:

(a) removal of usage-based charges, leaving nodal prices to coordinate grid usage (including by distributed generators)

(b) improved investment coordination incentives, because grid users are exposed to the costs of upgrading parts of the grid that will benefit them.

(c) all grid connected generators will contribute to common network costs via BBCs.

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74 https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/settlement-residual-allocation-methodology-sram/consultation/#c19217

75 South Island Mean Injection, or SIMI.

76 Regional Coincident Peak Demand, or RCPD.

77 TPM guidelines allow for a usage-based transitional congestion charge, and usage based kVAr charge. However, neither of these are included in the TPM that will apply from April 2023.

Transmission is a recoverable cost for distributors

C.12 Price-quality regulation of non-exempt distributors treats transmission as a recoverable cost.[78] Transmission-related recoverable costs include:

(a) transmission charges determined through the TPM

(b) costs of investment contracts with Transpower (or another transmission provider), and

(c) distributed generation allowances – including payments made to comply with the DGPPs.

C.13 Because a price-quality regulated distributor's transmission costs are recoverable in full (do not affect their revenue allowance), there is no financial business case for price-quality regulated distributors to pay distributed generators to avoid transmission costs unless those payments are also recoverable. This is because distributors cannot retain the benefit of avoided transmission costs. Similarly, there is no direct incentive for a distributor to minimise ACOT payments.

Flexibility funding is not widespread

C.14 Transpower has trialled arrangements for funding flexibility services but has not yet deployed widespread flexibility funding as a substitute for network investment. The lack of deployment of widespread flexibility funding may reflect some combination of:

(a) additional generation (beyond what is built and operating in response to nodal price signals and ACOT payments) not providing a cost-effective substitute – eg, because it is too costly, cannot be deployed in time or cannot provide an adequate level of service

(b) the incentives faced by Transpower (eg, the tension between efficiency and reliability objectives), noting that the Commerce Commission is currently considering the range of Part 4 efficiency incentives applying to Transpower through its input methodologies review process[79]

(c) Transpower's preferred approach of only contributing to distributed generation where that contribution is necessary to bring that generation into the market, or keep it operating[80]

(d) other barriers resulting, for example, from institutional or technical impediments.

C.15 This relative lack of activity is not necessarily indicative of a problem but does mean that arrangements for procuring network support services are not a mature or well-established feature of the New Zealand electricity market.

C.16 Payment to generators (or other flexibility providers) as a substitute for distribution network investment is also uncommon. As with transmission, this may reflect some combination of factors relating to the viability of generation solutions, the effectiveness of incentives and other impediments.

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[78] Refer clause 3.1.3 of Electricity Distribution Services Input Methodologies Determination 2012. https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf

[79] Information on the Commerce Commission's 2023 Input Methodology review can be found here: Commerce Commission - 2023 input methodologies review (comcom.govt.nz)

[80] Set out by Transpower as part of their process processes for identifying and assessing opportunities for transmission alternatives – see section 5 of this paper.

Price signalling for distributed generators is inefficient

C.17 Transmission costs are signalled to distributed and embedded (behind the meter) generators to some extent:

(a) nodal price signals are relevant to all generators

(b) for embedded generators, lines charges for load customers are also relevant.

C.18 There are a range of practices for how network costs are signalled to load (and hence to behind-the-meter embedded generators) through the electricity lines charges set by distributors:

(a) transmission pass-through practices vary[81]

(b) no distributor uses locational marginal pricing

(c) over-variabilisation is prevalent, meaning the price signal for embedded generation is typically too strong

(d) some distributors are beginning to transition to more cost-reflective pricing.

C.19 The DGPPs constrain price signalling for distributed generation, including because:

(a) distributed generators make no contribution to common costs

(b) distributors must pay distributed generators 100% of any avoided costs

(c) the incremental costs approach means charges are 'lumpy' as capacity is expanded.

C.20 These differences contribute to a lack of network neutrality, which can incentivise inefficient bypass and out-of-merit-order investment in generation. There are sources of bias toward distributed and embedded generation, including because:

(a) grid-connected generation will increasingly contribute to common transmission network costs (ie, interconnection costs), and receive efficient network usage and investment signals

(b) distributed generators pay only for incremental costs, and can be paid 100% of any avoided costs

(c) embedded generators typically make no contribution to costs, and typically receive a price signal based on avoiding fixed costs.

C.21 In addition, the existing price signals to distributed and embedded generation do not encourage efficient network usage, or investment coordination (ie, between networks vs. users).

C.22 The Authority is working with distributors to improve price signals for load (and hence behind-the-meter embedded generators), but Part 6 provides separate, more prescriptive regulation of pricing for distributed generators.

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81 The Authority is developing guidance on how distributors should allocate transmission charges under the new TPM. The guidance does not address allocation to distributed generators, because this is governed by the DGPPs.

Appendix D How to make a submission

D.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— consultation on ACOT payments to distributed generation' in the subject line.

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

D.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).

D.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.

D.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.

D.6 Please deliver your submissions by **5pm** on **Thursday 20 October 2022**. We plan to publish submissions on or around 21 October.

D.7 Please deliver your cross-submissions by **5pm** on **Thursday 3 November 2022**.

D.8 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 E Questions to assist submitters

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

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

E.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 background and context material in this chapter or Appendix A?
Response	
Chapter 3	# Do you agree with the Authority's preferred approach of clarifying that ACOT payments are no longer required? # Do you have any comments on the alternative approaches that could be used to justify ACOT payments? # Do you have any comments on the Authority's proposed amendments to the Code?
Response	
Chapter 4	# Do you agree with the transition risks we have identified, and our assessment of them? # Do you think there are any other transition risks we should consider? # Do you have any information that would allow the Authority and Transpower to better assess the risk that removing the requirement to make ACOT payments could lead to changes in distributed generation behaviour that could impact reliability? # Do you have any comments on the design of the phase-out option? # Do you agree with our preference that ACOT payment obligations cease from April 2023 with no phase out?
Response	
Chapter 5	# Do you have any comments on the distributed generation pricing context material provided in Appendix C? # Do you have any comments on the Authority's plans for further work on whether there is a future role for additional price signals for grid support technologies?
Response	
Chapter 7	# 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?
Response	

Appendix F Proposed Code amendments

F.1 This appendix provides drafting of our proposed Code amendments under each of our preferred option (see section 3) and the alternative phase-out option (see section 4).

F.2 The drafting is shown as a marked-up version of the relevant sections of the Code. Words with red text and with strikethrough indicate existing words we are proposing to delete, words with red text and without strikethrough indicate new words we are proposing to add.

F.3 The drafting for the phase-out option is the same as for our preferred option except it includes additional parts – these are indicated using bolded square brackets in the marked-up Code below.

Electricity Industry Participation Code 2010

Part 1
Preliminary provisions

1.1 Interpretation

(1) In this Code, unless the context otherwise requires,—

incremental costs, for the purpose of Part 6, means:

(a) the reasonable additional costs that an efficient **distributor** would incur in providing **electricity** distribution services ~~with connection services~~ to **distributed generation**~~, less the costs that the efficient **distributor** would incur if it did not provide those connection services~~; minus

(b) the **distribution** costs that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**[; minus

(c) any transitional amount calculated under clause 2D**]**.

Part 6
Connection of distributed generation

Schedule 6.4 cl 6.9
Pricing principles

1 This Schedule sets out the pricing principles to be applied for the purposes of Part 6 of this Code in accordance with clause 6.9 (which relates to clause 19 of Schedule 6.2 and clause 4 of Schedule 6.3).

Compare: SR 2007/219 clause 1 Schedule 4

Clause 1: amended, on 23 February 2015, by clause 69 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

2 The pricing principles are as follows:

Charges to be based on recovery of reasonable costs incurred by distributor ~~to connect~~as a result of connecting the distributed generator and to comply with connection and operation standards within the distribution network, and must include consideration of any identifiable avoided or avoidable costs

(a) subject to paragraph (i), connection charges in respect of **distributed generation** must not exceed the **incremental costs** of providing connection services to the **distributed generation**.~~To avoid doubt, **incremental cost** is net of—~~

~~(i) if the **distributed generation** is included in a list **published** by the **Authority** under clause 2C(1), transmission costs that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation** at the **nameplate capacity** specified for that **distributed generation** in the list; and~~

~~(ii) **distribution** costs that an efficient **distributor** would be able to avoid as a result of the **electrical connection** of the **distributed generation**:~~

(b) when calculating **incremental costs**, any costs that cannot be calculated ~~(eg, avoidable costs)~~ must be estimated with reference to reasonable estimates of how the **distributor's** capital investment decisions and operating costs would differ, in the future, with and without the generation:

(c) estimated costs may be adjusted ex post. Ex-post adjustment involves calculating, at the end of a period, what the actual costs incurred by the **distributor** as a result of the **distributed generation** being **electrically connected** to the **distribution network** were, and deducting the costs that would have been incurred had the generation not been **electrically connected**. In this case, if the costs differ from the costs charged to the **distributed generator**, the **distributor** must advise the **distributed generator** and recover or refund those costs after they are incurred (unless the **distributor** and the **distributed generator** agree otherwise):

Capital and operating expenses

(d) if costs include distinct capital expenditure, such as costs for a significant **asset** replacement or upgrade, the connection charge attributable to the **distributed generator's** actions or proposals is payable by the **distributed generator** before the **distributor** has committed to incurring those costs. When making reasonable endeavours to facilitate connection, the **distributor** is not obliged to incur those costs until that payment has been received:

(e) if **incremental costs** are negative, the **distributed generator** is deemed to be providing network support services to the **distributor**, and may invoice the **distributor** for this service and, in that case, the **distributed generator** must comply with all relevant obligations (for example, obligations under Part 6 of this Code and in respect of tax):

(f) if costs relate to ongoing or periodic operating expenses, such as costs for routine **maintenance**, the connection charge attributable to the **distributed generator's** actions or proposals may take the form of a periodic charge:

(g) *[Revoked]*

(h) after the connection of the **distributed generation**, the **distributor** may review the connection charges payable by a **distributed generator** not more than once in any

12-month period. Following a review, the **distributor** must advise the **distributed generator** in writing of any change in the connection charges payable, and the reasons for any change, not less than 3 months before the date the change is to take effect:

Share of generation-driven costs

(i) if multiple **distributed generators** are sharing an investment, the portion of costs payable by any 1 **distributed generator—**
   (i) must be calculated so that the charges paid or payable by each **distributed generator** take into account the relative expected peak of each **distributed generator's** injected generation; and
   (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(j) in order to facilitate the calculation of equitable connection charges under paragraph (i), the **distributor** must make and retain adequate records of investments for a period of 60 months, provide the rationale for the investment in terms of facilitating **distributed generation**, and indicate the extent to which the associated costs have been or are to be recovered through generation connection charges:

Repayment of previously funded investment

(k) if a **distributed generator** has paid connection charges that include (in part) the cost of an investment that is subsequently shared by other **distributed generators**, the **distributor** must refund to the **distributed generator** all connection charges paid to the **distributor** under paragraph (i) by other **distributed generators** in respect of that investment:

(l) if there are multiple prior **distributed generators**, a refund to each **distributed generator** referred to in paragraph (k) must be provided in accordance with the expected peak of that **distributed generator's** injected generation over a period of time agreed between the **distributed generator** and the **distributor**. The refund—
   (i) must take into account the relative expected peak of each **distributed generator's** injected generation; and
   (ii) may also have regard to the percentage of **assets** that will be used by each **distributed generator**, the percentage of **distribution network capacity** used by each **distributed generator**, the relative share of expected maximum combined peak output, and whether the combined peak generation is coincident with the peak load on the **distribution network**:

(m) no refund of previous payments from the **distributed generator** referred to in paragraph (k) is required after a period of 36 months from the initial connection of that **distributed generator**:

(n) to avoid doubt, nothing in Part 6 of this Code creates any **distribution network capacity** or property rights in any part of the **distribution network** unless these are specifically contracted for. **Distributors** must **maintain** connection and **lines** services to **distributed generators** in accordance with their **connection and operation standards**.

Compare: SR 2007/219 clause 2 Schedule 4

Heading: amended, on 23 February 2015, by clause 70(1) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2: amended, on 23 February 2015, by clause 70(2) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(a): amended, on 23 February 2015, by clauses 70(3) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(a): replaced, on 9 January 2017, by clause 4 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016.

Clause 2(a): amended, on 5 October 2017, by clause 73(1) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 2(c): amended, on 23 February 2015, by clauses 70(4) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(c): amended, on 5 October 2017, by clause 73(2) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 2(d): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(d), (f), (h), (j), (k), and (m): amended, on 5 October 2017, by clause 73(3) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

Clause 2(f): amended, on 23 February 2015, by clauses 70(5) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(g): revoked, on 23 February 2015, by clause 70(6) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(h): amended, on 23 February 2015, by clauses 70(7) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(i)(ii): amended, on 23 February 2015, by clause 70(8) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(j): amended, on 23 February 2015, by clauses 70(9) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(k): amended, on 23 February 2015, by clause 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(l)(ii): amended, on 23 February 2015, by clause 70(10) of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(m): amended, on 23 February 2015, by clauses 70(11) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(n): amended, on 23 February 2015, by clauses 70(2) and 75 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

Clause 2(n): amended, on 5 October 2017, by clause 73(4) of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.

~~**2A Transpower to provide reports to Authority in relation to distributed generation**~~

~~(1) **Transpower** must, by 15 March 2017 (or such later date as the **Authority** may allow),~~

~~provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(2) **Transpower** must, by 30 August 2017, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Lower North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(3) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper North Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(4) **Transpower** must, by 31 January 2018, provide a report to the **Authority** that identifies which (if any) **distributed generation** located in the Upper South Island is required for **Transpower** to meet the **grid reliability standards** in the period from 1 April 2017 to 31 March 2020.~~

~~(5) In this clause and clause 4,—~~

~~(a) Upper North Island is that part of the North Island situated on, or north and west of, a line—~~

~~(i) commencing at 38°02'S and 174°42'E; then~~

~~(ii) proceeding in a generally north-easterly direction directly to 37°36'S and 175°27'E; then~~

~~(iii) proceeding north along the 175°27'E line of longitude; and~~

~~(b) Lower North Island is that part of the North Island not referred to in subclause (a); and~~

~~(c) Upper South Island is that part of the South Island situated on, or north of, a line passing through 43°30'S and 169°30'E, and 44°40'S and 171°12'E; and~~

~~(d) Lower South Island is that part of the South Island not referred to in subclause (c).~~

~~Clause 2A: inserted, on 9 January 2017, by clause 5 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016.~~

~~Clause 2A(5): amended, on 5 October 2017, by clause 74 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.~~

~~**2B Authority to review Transpower's reports in relation to distributed generation**~~

~~(1) The **Authority** must, as soon as practicable after receiving a report from **Transpower** under clause 2A,—~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(2) If the **Authority** declines to approve the report,—~~

~~(a) the **Authority** must, as soon as practicable,—~~

~~(i) advise **Transpower** of its reasons for declining to approve the report; and~~

~~(ii) direct **Transpower** as to how it should amend the report before resubmitting it; and~~

~~(b) **Transpower** must amend the report in accordance with the **Authority's** direction, and resubmit the report to the **Authority**,—~~

~~(i) for the report provided under clause 2A(1), within 10 **business days**; and~~

~~(ii) for reports provided under clauses 2A(2), (3), or (4), within 20 **business days**.~~

~~(3) The **Authority** must, as soon as practicable after receiving a resubmitted report from **Transpower**,—~~

~~(a) approve the report; or~~

~~(b) decline to approve the report.~~

~~(4) Subclause (2) applies to the resubmitted report as if it were the report originally provided under clause 2A.~~

~~Clause 2B: inserted, on 9 January 2017, by clause 5 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016.~~

~~**2C Authority to publish list of distributed generation**~~

~~(1) The **Authority** must, after approving a report provided by **Transpower** under clause 2A, **publish** a list of **distributed generation** for the relevant region for the purposes of clause 2(a)(i).~~

~~(2) A list **published** under subclause (1) must include—~~

~~(a) only **distributed generation** that is connected as at 6 December 2016; and~~

~~(b) the **nameplate capacity** of the **distributed generation** as at 6 December 2016.~~

~~Clause 2C: inserted, on 9 January 2017, by clause 5 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016.~~

~~Clause 2C(2)(a): amended, on 5 October 2017, by clause 75 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.~~

[2D Avoidable costs of transmission transitional arrangements

(1) This clause applies where, in the **pricing year** immediately prior to the commencement of this clause, a **distributed generator** received payment from a **distributor** under clause 2(a)(i) as it applied prior to amendment.

(2) In respect of the 2 **pricing years** following the commencement of this clause, the **distributor** must, in calculating any **incremental costs** under clause 2(a), net off any amount calculated under subclause (3).

(3) The amount to be netted off under subclause (3) is to be calculated using:

(a) the **distributed generator's** average output across the 100 regional coincident peak **trading periods** specified by the **Authority** for this purpose; multiplied by

(b) **Transpower's** interconnection rate in dollars per kW for the **pricing year** immediately prior to the commencement of this clause, multiplied by:

(i) 0.5 for the first **pricing year** after the commencement of this clause; and

(ii) 0.25 for the second **pricing year** after the commencement of this clause.**]**

3 *[Revoked]*

Compare: SR 2007/219 clause 3 Schedule 4

Clause 3: revoked, on 23 February 2015, by clause 71 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2014.

~~**4 Delayed application of Electricity Industry Participation Code Amendment (Distributed Generation) 2016**~~

~~(1) Despite clause 2 of the Electricity Industry Participation Code Amendment (Distributed Generation) 2016,—~~

~~(a) until the close of 31 March 2018, Part 6 of this Code applies to the Lower South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and~~

~~(b) until the close of 30 September 2018, Part 6 of this Code applies to the Lower North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and~~

~~(c) until the close of 31 March 2019, Part 6 of this Code applies to the Upper North Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made; and~~

~~(d) until the close of 30 September 2019, Part 6 of this Code applies to the Upper South Island as if the Electricity Industry Participation Code Amendment (Distributed Generation) 2016 had not been made.~~

~~(2) In this clause, Upper North Island, Lower North Island, Upper South Island, and Lower South Island have the meanings set out in clause 2A(5).~~

~~Clause 4: inserted, on 5 October 2017, by clause 76 of the Electricity Industry Participation Code Amendment (Code Review Programme) 2017.~~

Glossary of abbreviations and terms

ACOD	Avoided cost of distribution
ACOT	Avoided cost of transmission
Act	Electricity Industry Act 2010
Authority	Electricity Authority
BBCs	Benefit-based charges
CMP	Capacity measurement period
Code	Electricity Industry Participation Code 2010
DG	Distributed generation
DGPPs	Distributed generation pricing principles
EDB	Electricity distribution business or businesses
GRS	Grid reliability standards
GW	Gigawatt
kW	Kilowatt
kWh	Kilowatt hour
kVAr	KiloVolt Ampere reactive
LNI	Lower North Island
LSI	Lower South Island
MW	Megawatt
MWh	Megawatt hour
RCPD	Regional coincident peak demand
SPD	Scheduling, pricing and dispatch model
TPM	Transmission Pricing Methodology
Transpower	Transpower New Zealand Limited
UNI	Upper North Island
USI	Upper South Island