

17 May 2016

**Consumer Guide:
Have your say on pricing guidelines and methodologies**

1. We want your views on proposed changes

- 1.1 The purpose of this consumer guide is to give you a summary of two important consultations on electricity pricing. We are seeking your views on proposed changes to:
 - (a) how Transpower allocates charges among its customers (the transmission pricing methodology, or TPM)
 - (b) the pricing arrangements for electricity generators connected to a local distribution network (known as distributed generation).
- 1.2 The guide is divided into two parts. Part A summarises our TPM proposal. Part B summarises our distributed generation proposal. We have released the two papers at the same time because of the close relationship between the two projects.
- 1.3 We are seeking submissions on both proposals. Please remember that this consumer guide is a simplified summary. It is intended to inform consumers about the proposals. It is not intended to be used for consultation.
- 1.4 Should you wish to make a submission, please read the consultation papers.
- 1.5 Submissions on both the TPM proposal and the distributed generation proposal are due by 5pm on 26 July 2016.

We are proposing changes to pricing for transmission services

- 1.6 In the consultation papers, we are proposing to publish new Guidelines that Transpower needs to follow to develop a new TPM. The proposals would require Transpower to replace two charges in the current TPM with two new charges and to change the circumstances in which Transpower can provide discounts on transmission charges. We are also proposing other changes, outlined later in this paper.
- 1.7 In essence, we are proposing these changes so that the parties that benefit from transmission services pay for those services, at a level that reflects the cost of providing those services.
- 1.8 Under the current approach, for example, generators pay nothing for the largest component of transmission – called the interconnection service. Charging generators for using the interconnection service will encourage them to make better decisions about where they locate their power stations, which means we can avoid wasteful investment in the electricity industry.
- 1.9 Conversely, currently only South Island generators pay for the transmission link between the North and South Islands (called the HVDC link) even though North Island consumers receive the highest proportion of the benefits from the HVDC service. This approach also encourages wasteful investment in the transmission system.
- 1.10 Also, under the current approach, electricity distributors and some large industrial companies¹ pay for the interconnection service. Their charges are calculated in a way that discourages them from using the service when there is plenty of spare room (ie, spare capacity) on the system. This encourages distributors to pay the owners of distributed

¹ Collectively, electricity distributors and industrial consumers directly connected to the grid are referred to as “load” transmission customers.

generation to produce electricity when there is no need for that to occur as there is plenty of spare capacity on the transmission system.

- 1.11 These are just some of the many wasteful activities that occur as a result of the current TPM. The changes we are proposing should discourage these kinds of wasteful activities, reducing the cost of electricity to consumers over the long term.

We are proposing changes to pricing for distributed generation

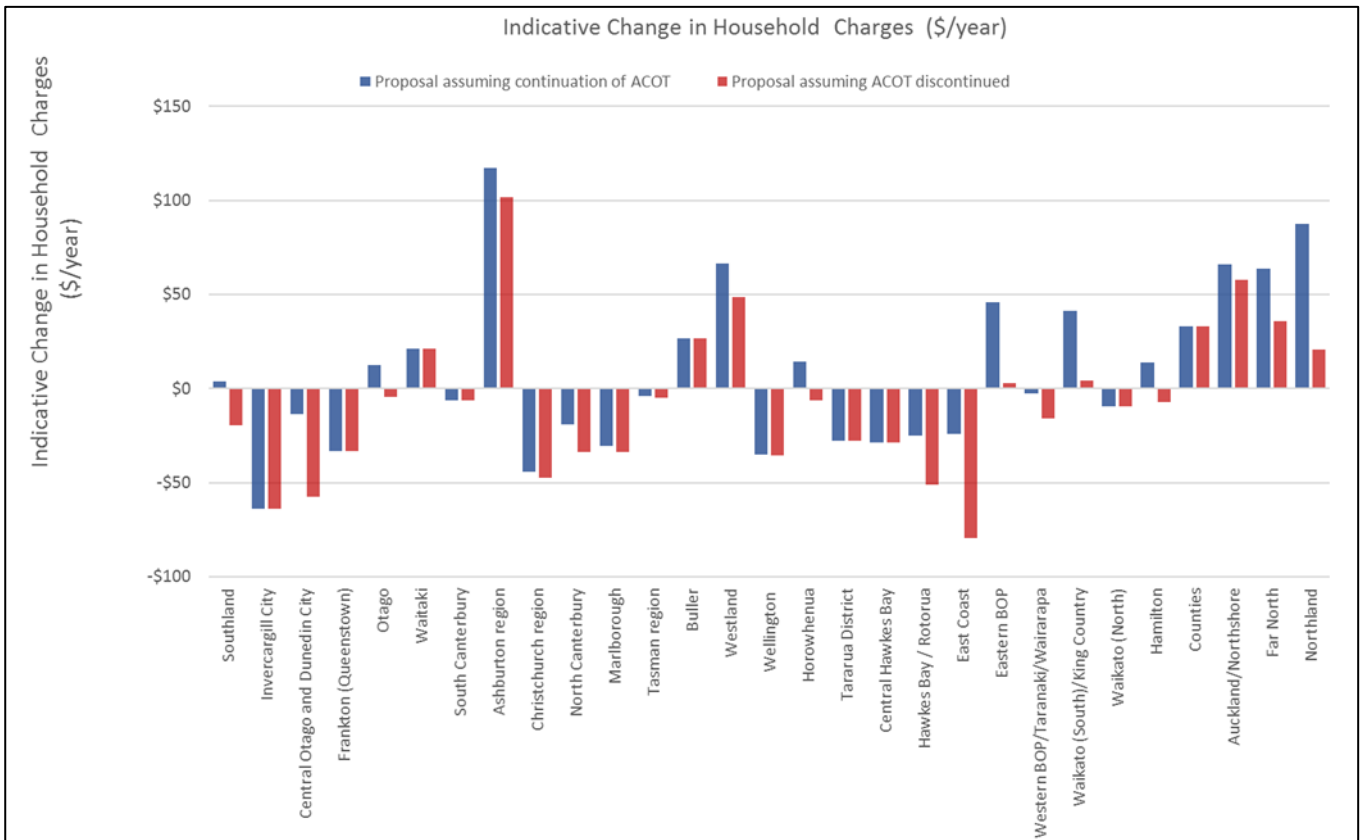
- 1.12 In another consultation paper we are proposing to change the pricing arrangements for electricity generators that are connected to a local distribution network (known as distributed generation). The purpose of these changes is to encourage distributed generation to operate only when it is for the long term benefit of consumers.
- 1.13 As indicated above, our proposed changes to the TPM Guidelines would affect payments to distributed generation. Regardless of what we decide on the TPM, however, we are proposing to alter the pricing arrangements for distributed generation—hence, we are consulting separately on this issue as well as on the TPM issue.

The overall impact on you

- 1.14 We have calculated the potential initial impact of both proposals on the final bill for residential electricity consumers.² The overall impact on you depends on where you live and how much electricity you consume.
- 1.15 The chart below shows the proposals would initially increase prices in some regions of New Zealand and reduce prices in other regions. The blue bars show changes in charges under the Authority's TPM proposal assuming payments to distributed generation continue whereas the red bars assume those payments are discontinued.
- 1.16 For regions where electricity prices would increase, the bill for an average residential consumer increases less than \$50 per year. The Ashburton region faces the highest price increases, with an average residential consumer facing an increase in their annual electricity bill of \$117. For consumers in other regions, the proposals would reduce their prices (assuming no other changes in the electricity industry).

² Note these calculations do not include any allowance for prudent discounts as we won't know those until discount applications are made.

Figure 1: Indicative change in the annual electricity bill for an average household in each region (\$ per year)



- 1.17 To put these initial price effects into perspective, on average consumers can immediately save more than \$150 by switching from their current electricity retailer to the cheapest retailer in their region.
- 1.18 The above chart shows only the initial impact. The longer-term impact of the proposals would be to reduce charges overall for consumers due to less wasteful investment occurring in the electricity sector.
- 1.19 As it will take several years to implement the proposals, if we proceeded with them, then the price changes in the above chart are not likely to occur until 1 April 2019.
- 1.20 Further charts showing the potential impact of the proposals are provided on pages 22-23 of this guide.

Part A: Transmission pricing methodology

2. We are proposing three main reforms to the TPM

- 2.1 Transpower builds, operates and maintains the national transmission grid, and most of its revenue comes from charging customers for using the grid. Transpower's customers are electricity generators, electricity distributors, and some large industrial companies.
- 2.2 The Authority sets the Guidelines that Transpower must follow to develop a TPM. The TPM Guidelines set out which transmission customers are responsible for paying Transpower for the regulated components of the transmission grid. The TPM Guidelines also specify, at a high level, how to calculate the charges for each transmission customer.
- 2.3 In summary, we are proposing two new charges to replace two existing charges:
- (a) We are proposing transmission customers be charged only for the grid services they receive and at a price level that reflects the cost of the services delivered to them.

This new approach is called the *area-of-benefit (AoB) charge*, because the aim is to identify areas of the country receiving benefits from particular grid investments and charge transmission customers in those regions accordingly.

We are proposing the area-of-benefit charge be applied to all future grid investments, to recent grid investments exceeding \$50 million in value and to Pole 2 of the HVDC link (see later discussion about the HVDC). It is not practicable, however, to implement the area-of-benefit charge for all existing grid assets.
 - (b) We are also proposing the TPM include a *residual charge* to cover costs not covered by other charges in the TPM. However, over time, the area-of-benefit charge will reduce the residual charge as existing grid assets are refurbished or replaced.
- 2.4 Together, the area-of-benefit and residual charges would replace two main charges in the current TPM, called the HVDC charge and the interconnection charge. Further details about these charges are provided at paragraph 4.1 (page 16 of this guide).
- 2.5 The current TPM includes a *prudent discount policy (PDP)*. We are proposing to keep the PDP but add some new features to allow a wider range of circumstances for providing discounts on transmission charges. The purpose of this change is to broaden the application of the PDP to cover other instances where transmission customers may undertake wasteful activity and, as a result, increase charges on other transmission customers.
- 2.6 The TPM Guidelines also include other features, and the Authority is also proposing changes to the Code, which are detailed later in this paper.³
- 2.7 We expect our proposal to provide much stronger incentives for transmission customers (that is, generators, distributors and industrial consumers) to make better investment and operational decisions about using the transmission grid. Better customer decisions will lead to much better grid investment decisions, minimising transmission costs and minimising electricity prices to consumers.

³ We propose two changes to the electricity market rules—called the Electricity Industry Participation Code 2010 (Code)—to deal with issues related to the TPM.

- 2.8 This document discusses our proposal and why we are proposing new TPM Guidelines:
- (a) this section describes our proposal
 - (b) section 3 looks at the transmission system and principles for transmission pricing
 - (c) section 4 describes the current TPM
 - (d) section 5 explains the perverse results the current TPM produces
 - (e) section 6 examines the impact of the proposal on consumers and other grid users.

Next steps

- 2.9 Consultation closes on 26 July 2016. We will then:
- (a) publish submissions on the proposal
 - (b) consider those submissions
 - (c) if we decide that a change to the TPM Guidelines promotes the long term benefit of consumers, we will publish final Guidelines for Transpower to follow in developing the TPM and a final process for the development of a TPM.
- 2.10 If, after considering submissions, we decide to implement this proposal, we aim to have the new TPM in place for the April 2019 pricing year.

We are proposing pragmatic and practical reforms to the TPM

- 2.11 The proposals outlined below are based on three key principles for transmission pricing:
- (a) if practicable, transmission prices should be determined through the interaction of buyers and sellers in a workably competitive market
 - (b) if it isn't possible to set prices through market interactions, then prices will need to be set administratively—these prices should be service-based and cost-reflective
 - (c) overall, the TPM should be practicable to implement and administer, and it should be easy for transmission customers to verify their charges are correct.
- 2.12 *Service-based pricing* occurs when only those customers receiving the benefits of a service pay for that service. This means parties that don't receive the service are not charged for it. It also means transmission customers pay higher prices for higher service levels and lower prices for lower service levels. *Cost-reflective pricing* is when the price for a transmission service reflects the cost of delivering the service. Both approaches mimic what happens when prices are set through market interactions.
- 2.13 The reforms we are proposing are pragmatic and practical. For example, to avoid disruptive changes (now and over time), we are proposing to retain the current approach of spreading the cost of most existing interconnection assets across all distributors and large industrial consumers—this will be done through the residual charge.
- 2.14 However, we are proposing the residual charge would be calculated on the basis of each load customer's physical capacity, rather than their share of current peak demand. Charging by current peak demand is imposing substantial economic costs on the electricity system, and therefore ultimately on consumers.
- 2.15 The original reason for setting charges on the basis of current peak demand was to encourage distributors and large industrial companies to alter their behaviour to defer costly investment in the transmission grid. The new area-of-benefit charge should provide better

price signals to encourage that behaviour change when it is needed, and without imposing substantial economic costs on the electricity system.

We are proposing the new TPM would have four main components

- 2.16 We consulted in 2015 on three TPM options, each with seven components. We received many valuable submissions, and we are now proposing one TPM option with four main components, described below.⁴

Component 1: retain the current connection charge

- 2.17 The current connection charge is considered to be working pretty well, as the charges are service-based and largely cost-reflective. However, there are some aspects that need improving.
- 2.18 We are therefore proposing to retain the current connection charge, but with potentially some minor changes to deal with:
- (a) situations where the commissioning of transmission assets occurs in stages
 - (b) charging for transmission assets when their classification changes from connection to non-connection
 - (c) charging for operating and maintenance costs on an actual cost basis.

Component 2: a new area-of-benefit charge

- 2.19 We are proposing a new area-of-benefit charge to recover the cost of new (and major recent) investments in the interconnected grid. The interconnected grid comprises interconnection assets in each Island and the high-voltage direct current (HVDC) link between the North and South Islands.
- 2.20 Adopting the area-of-benefit charge would mean those who benefit from an investment in the interconnected grid will pay the costs of using those assets. This contrasts with the current approach, where parties pay for investments in the interconnected grid regardless of whether they receive any benefit from those investments.
- 2.21 Under the proposed approach, Transpower would apply the area-of-benefit charge to four categories of investments (called “eligible investments”):
- (a) any HVDC or interconnection investments commissioned after the proposed Guidelines are published, although initially this may be limited to investments exceeding \$5m in value at the time of commissioning⁵
 - (b) any existing HVDC and interconnection investments approved after May 2004, and before the Guidelines are published, and exceeding \$50m in value at the time of commissioning

⁴ The current TPM also has four main components: a connection charge, an interconnection charge, an HVDC charge and a prudent discount policy.

⁵ To reduce administration and transaction costs, the Authority is proposing that a simplified area-of-benefit charge apply to new eligible investments valued at less than \$5 million at the time of their commissioning. The simplified area-of-benefit charge may not be levied on all beneficiaries of an investment, may not be reviewed when a material change of circumstances occurs and may not allow marginal cost or optimisation adjustments (optimisation is discussed later in this paper). The proposed Guidelines require Transpower to propose a transition plan for phasing in the simplified charge over time.

(c) Pole 2 of the HVDC link⁶

(d) if not covered in the investments above, costs incurred by Transpower to avoid transmission investment (for example, payments made to distributed generation).

2.22 This means that most existing interconnection assets would not be subject to the area-of-benefit charge. Instead, the cost of those assets would be recovered with a residual charge spread across load customers. See Component 3 below for further detail about this charge. Together, the area-of-benefit and residual charges would replace the HVDC and interconnection charges in the current TPM.

2.23 We are proposing that:

(a) Both load and generation customers pay the area-of-benefit charge. This is a change from current HVDC and interconnection charges, where only South Island generators pay the HVDC charge and only load customers pay the interconnection charge.

(b) As far as possible, load and generation pay the area-of-benefit charge in proportion to the benefits that Transpower estimates they will receive from each eligible investment.

2.24 In terms of working out the details of the new approach, we are proposing that Transpower develops and proposes to the Authority methods and processes for:

(a) determining which areas of the country, and therefore which individual parties, benefit from each eligible investment

(b) reviewing the estimate of benefits for any eligible investment if there is a material change of circumstances.

The proposed methods for valuing assets for the area-of-benefit charge

2.25 For calculating the area-of-benefit charge on eligible investments, we are proposing to retain the depreciated historic cost (DHC) approach for valuing existing assets,⁷ and to value new assets at replacement cost (RC), with values being updated periodically.⁸ The Authority does not, however, have a firm view about whether the RC approach for new assets is appropriate and may adopt one of the other approaches outlined in the main consultation paper. However, to simplify the discussion below, the rest of this paper is written as if the RC approach will be adopted.

2.26 When Transpower upgrades or replaces existing grid assets, the charge used to recover the costs of the upgraded/replaced assets will change from the residual charge to the area-of-benefit charge. As a result, over time charges for HVDC and interconnection assets will automatically transition from DHC to RC values.

2.27 DHC values take the age of assets into account. The DHC valuation approach works best in markets where the age and condition of assets affects the benefits customers receive from the service delivered by the asset. For example, newer rental cars are often charged at a higher rate than older ones.

⁶ The HVDC link consists of two separate circuits with major converter systems at each end. These converter systems are called Poles.

⁷ The proposed approaches detailed in this paper do not change the overall revenue collected by Transpower.

⁸ RC is the current market cost to replace an existing asset with a new asset with equivalent service attributes. DHC is the standard accounting treatment of assets, where the purchase (that is historic) cost of an asset is depreciated over time.

- 2.28 RC charges are based on the cost to replace the asset (and therefore continue the service). The age and condition of the assets are largely irrelevant to determining the charging basis.
- 2.29 For transmission services, the RC approach is more consistent with a service-based approach to pricing because, in general, the service provided by transmission assets varies little with the age of the asset.

We are also proposing to allow “optimisation” in certain circumstances

- 2.30 When assets are not used to the extent originally envisaged, a service-based approach suggests that customers do not pay for what they do not use. We are proposing to reflect such changes in use by reducing asset values—the process for doing this is called optimisation.
- 2.31 We are proposing that parties can apply for optimisation for both existing assets and new assets.
- 2.32 Optimisation will help address the issues that arise when a large transmission customer leaves a region, effectively stranding assets (at least in part), as has happened on the West Coast. This is because the remaining customers would face a charge that reflects the costs of assets needed to meet their expected use of the asset, even though the assets were actually built to also cater for the large transmission customer that has left the region.
- 2.33 Under normal circumstances, parties would not be able to request optimisation for a period of time, such as ten years, after commissioning a transmission investment. We are proposing to make an exception to this rule: when the exit of a large customer leads to a significant difference between the replacement cost of an investment and the optimised replacement cost of an investment.
- 2.34 We do not expect optimisation to address all situations where charges would increase in a region, following the implementation of an area-of-benefit charge. For example, Top Energy and Northpower are expected to receive increases in their transmission charges, mostly because they are major beneficiaries of the North Auckland and Northland (NAaN) grid upgrade and the North Island Grid Upgrade (NIGU). Recent investments have improved service levels, especially reliability, to those regions and the increase in prices would reflect this. Asset optimisation is not intended to address such situations.

Component 3: a new residual charge on load

- 2.35 The area-of-benefit charge is intended to be the primary charge for HVDC and interconnection services. However the area-of-benefit charge, along with the other potential proposed charges (see “Other aspects of the Authority’s proposal” below), would not recover all of Transpower’s regulated revenue requirements. We propose a residual charge to recover the balance of revenue that Transpower is entitled to.
- 2.36 In designing the residual charge, we want to avoid creating incentives for parties to invest in costly alternatives to avoid the charge when those alternatives do not reduce transmission costs.
- 2.37 For example, under the current interconnection charge there are strong incentives on the owners of distributed generation to produce electricity when there is no need for that to occur as there is plenty of spare capacity on the transmission system.
- 2.38 The proposed new residual charge is designed to discourage those kinds of wasteful activities, which should reduce the cost of electricity to consumers over the long term. We are proposing to achieve this by allocating the residual charge to load transmission

customers based on the physical capacity of the grid that serves each specific customer. Under this approach, it only makes sense for parties to invest in alternatives (such as distributed generation) when doing so defers the need for more costly transmission upgrades.

- 2.39 Given Transpower is entitled to recover its revenue up to its maximum allowable revenue set for it by the Commerce Commission, the residual charge will be used to recover the remaining cost of an optimised asset. Therefore, the more optimisation on the grid for TPM purposes, the larger the residual charge.
- 2.40 However, we expect the residual will reduce over time as old assets are upgraded or replaced and the cost of those replacements is recovered through the area-of-benefit charge.

Component 4: retain prudent discount policy, with improvements

- 2.41 The current TPM includes a prudent discount policy (PDP) to encourage customers to remain connected to the grid, or avoid bypassing it, when this avoids large economic costs for the electricity industry.
- 2.42 Granting discounts in these situations is a 'win-win' for transmission customers. This is because granting a prudent discount can lower charges for all customers as it reduces the transmission charge on a customer if two conditions hold:
- (a) their normal charge would result in the customer disconnecting from the grid, and
 - (b) that disconnection would increase the charges on other customers.
- 2.43 The existing prudent discount policy does not provide for all situations where the outcomes in (a) and (b) above can occur. We are therefore proposing to make the prudent discount available where:
- (a) it is more expensive for a load customer to pay transmission charges than invest in generation that avoids the need to connect to transmission, or
 - (b) there is a material risk that a Transpower customer or a large customer within a distribution network would exit. Note, we are proposing that these discounts be linked to key factors affecting the decision to exit, such as the world price of the product produced by the firm. This will ensure the firm's transmission charges increase if the firm's market conditions recover materially.
- 2.44 We also consider that the current maximum 15 year term for prudent discounts is not long enough. Prudent discounts would be available for the expected life of the asset to which they apply (although the extent of the discount may vary if a discount is linked to market conditions – for example, market conditions may improve to a level that means that the discount is very small or nothing at all).

Other aspects of the Authority's proposal

- 2.45 We have proposed five additional components for Transpower to include in the TPM if practicable and if certain other requirements are met. These components relate to:
- (a) situations when transmission assets are commissioned in stages – in early stages the assets may be classed as connection assets, but in the final stage they may become non-connection assets
 - (b) charging for assets when their classification changes from connection to non-connection when this occurs as a result of other investments made in the grid

- (c) allocating operating and maintenance costs for connection and area-of-benefit assets based on actual costs
- (d) a long-run marginal cost (LRMC) charge
- (e) a kvar charge.

2.46 To find out about the five additional components read chapter 7 of the consultation paper.

Comparison with Application B in the TPM options working paper

- 2.47 We are proposing to apply the area-of-benefit charge to existing grid investments costing more than \$50m that were approved after May 2004. One of the major investments in that category is Pole 3 on the HVDC link, which replaced Pole 1.
- 2.48 The HVDC link now comprises (an old) Pole 2 and (a new) Pole 3. As both poles provide the same service (transporting electricity between the North and South Islands), the Authority is proposing to apply the area-of-benefit charge to Pole 2 even though investment in it was approved many years before May 2004.
- 2.49 This means that the charging basis is the same for both large recent and future investments and for both Poles of the HVDC. The Authority considers this approach is important for ensuring that a new TPM is durable. A durable TPM would help reduce uncertainty, and therefore promote efficient investment, which would be to the long-term benefit of consumers.
- 2.50 In the previous TPM consultation paper we canvassed the idea of applying the new area-of-benefit charge solely to new investment—this was called “Application B” in the 2015 TPM options working paper.
- 2.51 Applying new area-of-benefit charges only to new investments is very unlikely to be durable because:
- (a) it would not resolve the concern of some stakeholders with the current TPM that their charges do not reflect the underlying cost of providing them with transmission services and the benefits they receive
 - (b) regions that require major investments in the near future would pay for that major investment, while continuing to pay part of the costs of recent major investments from which they do not benefit.⁹
- 2.52 If the Authority had opted for Application B, regions that have had recent significant transmission investment such as Auckland would continue to have a large portion of the cost of those investments paid for by other regions. However, regions that are the beneficiaries of new investments would be required to pay the full cost of those new investments as well as a portion of Auckland’s historical investments.

⁹ Several submitters to the TPM options working paper made this point, including for example Orion (p.9) and Alliance Group (p.2).

3. The principles of effective transmission pricing

Background on the transmission system

- 3.1 Transpower builds and operates transmission lines and associated infrastructure such as substations and transformers. These are called transmission assets, and the national grid comprises all of those assets. Grid circuits are specific transmission lines and associated assets such as transformers.
- 3.2 Transpower provides an interconnected system that is shared by many transmission customers. The interconnected system comprises interconnection assets in each Island and the HVDC link between the North and South Islands. Electricity flows across multiple circuits on an interconnected system to reach its destination, and congestion on one circuit can alter power flows right across the system.
- 3.3 The interconnected grid transports electricity across New Zealand, typically from regions with plentiful low-cost sources of generation to regions where electricity demand exceeds generation. Insufficient capacity on some grid circuits means that it is not always possible to transfer all available energy from regions with low generation costs to regions with higher cost sources of generation.¹⁰
- 3.4 Transpower also builds and operates transmission assets to connect electricity generators, electricity distributors and large industrial consumers to the interconnected grid.¹¹ These are called connection assets, and we often refer to Transpower as providing connection services. Most of Transpower's connection services are provided to single customers but there are some cases where two or more parties share connection assets.
- 3.5 The connection assets for distributors are like the on-ramps and off-ramps that connect a city's local roads to the motorway system. But there are also large connection assets that serve generators and industrial consumers. These assets can be long and stringy if they're serving a generator or industrial consumer located in a remote area of New Zealand.
- 3.6 Connection assets transport electricity from generation plants to a point of connection on the interconnected grid. From that point, electricity is transported over the interconnected grid to large industrial consumers and electricity distributors, and distributors distribute the electricity locally to consumers connected to their network.
- 3.7 The national grid is a natural monopoly service. As a result, the Commerce Commission approves the total amount that Transpower can charge annually, and the Authority approves the methodology by which Transpower charges its customers—this is called the transmission pricing methodology, or TPM.

Good transmission pricing delivers long-term benefits to consumers

- 3.8 It is the Authority's role to ensure that transmission prices promote long-term benefits to consumers. We published a Decision-making and Economic Framework (DME Framework)

¹⁰ In this paper, the capacity of a circuit refers to the maximum amount of energy that is allowed to be transmitted over the circuit. This maximum is determined by a range of factors and doesn't necessarily equal the physical capacity. For example, Transpower limits energy flows on electrical circuits to satisfy security requirements.

¹¹ Most consumers are connected to local electricity distribution networks, who in turn are connected to the national grid. Some large industrial consumers, however, are directly connected to the national grid, and so they are called grid-connected consumers (GCCs).

for good transmission pricing in May 2012.¹² The consultation paper on the Authority proposal elaborates on this further.

- 3.9 The DME Framework and the consultation paper set out the Authority's view that, for transmission prices to promote long-term benefits to consumers:
- (a) transmission prices should be determined through the interaction of buyers and sellers in a workably competitive market—this is called the market-based approach
 - (b) if it isn't possible to set prices through market interactions, then prices will need to be set administratively and these prices should be set so they are service-based and cost-reflective
 - (c) the pricing methodology should be practicable and involve low transaction costs.¹³

Prices should be service-based and cost-reflective

- 3.10 Transmission customers make consumption, production and investment decisions based on the private benefits and costs of the choices available to them.
- 3.11 *Service-based pricing* is when the cost of a transmission service is charged only to those customers receiving the benefits of a service. This means the cost of the service is not charged to other transmission customers receiving other transmission services. It also means transmission customers pay higher prices for higher service levels and lower prices for lower service levels.
- 3.12 *Cost-reflective pricing* is when the price for a transmission service reflects the cost of delivering the service.

¹² This is called the Decision-making and Economic Framework for Transmission Pricing, which is available at <http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/development/economic-framework-decision-making/>. Chapter 5 of the consultation paper provides further elaboration of the framework.

¹³ A transaction cost is a cost incurred in an economic exchange, such as in this case the consumption of, and payment for, transmission services.

An example of what can go wrong if parties don't pay charges reflecting the costs of what they use

For example, suppose a company is considering whether to build a gas-fired generation plant in Auckland (close to its customers) or in Taranaki (close to gas fields):

- if it builds the plant in Auckland, then it has to use gas pipelines to transport gas from Taranaki to Auckland (called gas transmission)
- alternatively, if it builds the plant in Taranaki it will need to use electricity interconnection assets to transport its power to Auckland.

Currently, generators have to pay for the pipeline that transports the gas for their generation but not the transmission lines that export the power they generate. This means in our example the company building the gas-fired generator faces strong incentives to build it in Taranaki because it will pay zero charges for using interconnection assets to transport its electricity to Auckland (and other parts of the grid). Building in Taranaki is likely to be cheaper for the company even if it is more costly to the economy than building in Auckland and using the gas pipeline.

Also, the company has strong incentives to tell Transpower and the Commerce Commission that the electrical circuits bringing power from Taranaki to Auckland need to be upgraded if they become congested, even though the congestion partly results from locating the generator in Taranaki. The electricity customers will pay for the circuit upgrades, even though they arose from the decision to locate the gas generator plant in Taranaki.

Moreover, given that the generator is in Taranaki, the Commerce Commission's independent and impartial assessment of the economic benefits of upgrading those circuits will be much higher than it would be otherwise. This means the Commission's decision-making is affected by the generator's location decisions and leads to higher-cost outcomes overall.

3.13 The above example illustrates that transmission users should face the full cost of providing them the services they benefit from as this provides economic benefits through better production and investment decision-making.

3.14 Where the services are shared with other parties, the best approach is to charge all parties at least the *incremental cost* of the service delivered to them and no more than the *stand-alone cost*.¹⁴

¹⁴ Incremental costs (IC) are the additional costs of providing one more transmission customer with transmission services, or providing existing customers with additional services. Stand-alone costs (SAC) are the costs of providing transmission services or equivalent alternative services to a single customer or subset of customers. These costs are usually estimated by considering the costs of a purpose-built transmission facility (or alternative facility) to suit the needs of the customer(s). In summary, the pricing rule is: $IC < price < SAC$.

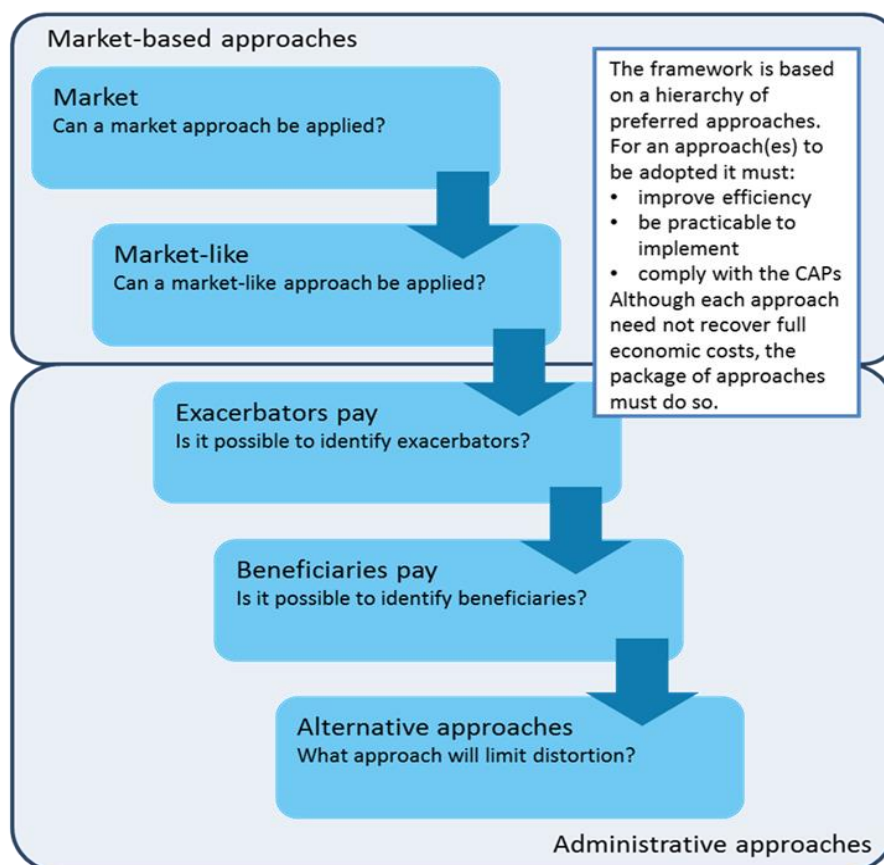
Price setting should reflect practicality and transaction costs

- 3.15 The above principles for good transmission pricing are relatively straight forward to apply for connection services provided to a single connection customer. However, many parties share the interconnected grid, and it isn't obvious who uses which grid circuits. We need a method to assign the services of particular circuits to particular grid users.
- 3.16 In practice, Transpower incurs significant costs to administer the TPM. Transmission customers also face significant costs to verify they are being charged in accordance with the methodology. These costs are referred to as transaction costs.
- 3.17 If multiple components to the TPM and complicated methodologies mean high transaction costs, then adopting a small number of components and less rigorous approaches that simplify the TPM can be more cost-effective.

We developed a hierarchy of approaches to transmission pricing

- 3.18 The DME Framework sets out a hierarchy of approaches to transmission pricing, as illustrated in Figure 2 below.

Figure 2: Decision-making and economic framework for transmission pricing



- 3.19 Figure 2 shows the Authority's first preference is for market-based approaches for determining TPM charges. A market-based approach sets charges through the interaction of buyers and sellers in a workably competitive market. As prices in workably competitive markets are service-based and cost-reflective to the extent practicable, they fit well with the transmission pricing principles listed above.

3.20 However, market-based approaches are not always good for consumers. Transmission is a monopoly service (there is only one provider), so we need administrative approaches to deliver better outcomes for consumers.

3.21 Under administrative approaches, the Authority's order of preference is:

- (a) *An exacerbators pay charge.* An exacerbator is a party whose action (or inaction) led to a particular cost and who would change its behaviour to avoid or reduce the cost if it had to pay.
- (b) *A beneficiaries pay charge.* A beneficiary is a party for whom the private benefits of the investment exceed its share of the costs and who would therefore be willing to pay for a portion of the investment if that were the only means of acquiring the benefit.
- (c) *Alternative (charging) approaches,* where the costs are spread across the users of transmission services where the costs of a transmission service are spread across transmission users regardless of whether they receive that service or not.

3.22 The approaches in (a) and (b) are consistent with the service-based and cost-reflectivity principles discussed above. The alternative charging options can be consistent with cost-reflectivity but are not service-based.

4. What is the current TPM?

4.1 The current TPM comprises three charges:

- (a) *A connection charge,* which recovers the costs of assets connecting transmission customers to the transmission grid. Connection charges are paid by generators, distributors and direct consumers. Total connection charges were approximately \$128 million for the 2015/16 year.
- (b) *An HVDC charge,* which recovers the costs of the HVDC link between the North Island and the South Island. HVDC charges are paid by generators located in the South Island, currently on the basis of their share of maximum injections to the grid in the South Island over the preceding five-year period.

As the calculation is based on maximum injections during the preceding five years, the allocation method is called historical anytime maximum injection (HAMI). Some people refer to the HVDC charge as the HAMI charge. HVDC charges were approximately \$150 million for the 2015/16 year.¹⁵

- (c) *An interconnection charge,* which recovers the remainder of Transpower's regulated revenue requirements from distributors and direct consumers. The interconnection charge is based on each payer's share of demand at peak times in one of four transmission regions—the upper North Island (UNI), the lower North Island (LNI), the upper South Island (USI) and the lower South Island (LSI). Interconnection charges

¹⁵ As a result of a recent operational review by Transpower, the Authority has recently approved an amendment to the HVDC charge to replace the HAMI allocator with an allocator based on the total injection by each South Island generator, averaged over five years. The new basis for allocating the HVDC charge is called South Island Mean Injection (SIMI). The Authority has approved a four-year transition from the HAMI-based charge to the SIMI-based charge.

were approximately \$639 million for the 2015/16 year.

The payer's share of demand at peak times is called the payer's regional coincident peak demand (RCPD) and the interconnection charge is called the RCPD charge by some people.

- 4.2 Total transmission charges are forecast to reach approximately \$918 million in 2015/16. Transpower is forecasting its regulated transmission charges for 2019/20 will have increased by around 55% since 2010/11, due primarily to investment in interconnection assets.
- 4.3 On average, currently, transmission charges make up 10% of residential electricity bills paid by households.
- 4.4 The current TPM includes a *prudent discount policy* (PDP). As discussed in the proposal, the purpose of the PDP is to discount transmission charges to avoid uneconomic bypass of existing grid assets. The PDP does this by discounting the charges for a party who would otherwise not connect to the transmission grid or would disconnect from the grid.¹⁶ The costs of agreed prudent discounts are recovered from other transmission customers in accordance with the TPM. Only three prudent discount agreements have been made since the current TPM was implemented in 2008, although some legacy discounts made under notional embedding agreements (the precursor to the PDP) remain.

How the current TPM relates to the hierarchy illustrated above

- 4.5 We consider connection charges to be very close to market-based charges because each connection customer negotiates its connection services with Transpower. Each connection customer is free to build its own connection assets if it disagrees with Transpower's proposed connection charges.
- 4.6 The HVDC charge is a crude beneficiaries pay charge. The decision in the 1990s to charge HVDC costs to South Island generators was based on the assumption that those parties benefit from the HVDC. It is a crude beneficiaries pay approach because the charges to South Island generators are not allocated according to their share of the benefits (these benefits are not measured). And other parties that benefit greatly from the HVDC, such as North Island consumers, do not pay any HVDC charges.
- 4.7 Although there are four transmission regions,¹⁷ the cost of interconnection is in effect spread across all distributors and direct consumers (called 'load customers') regardless of which parts of the interconnection system they use. Moreover, generator customers don't pay anything for using the interconnection system to transport their electricity to load customers. Since the current interconnection charge is spread broadly (across all load customers) it sits at the bottom of the hierarchy, in the category called alternative charging options.

¹⁶ The current PDP requires a party to have the ability to undertake a project that would allow them to bypass the grid, and requires that the discount be based on the costs of the alternative project.

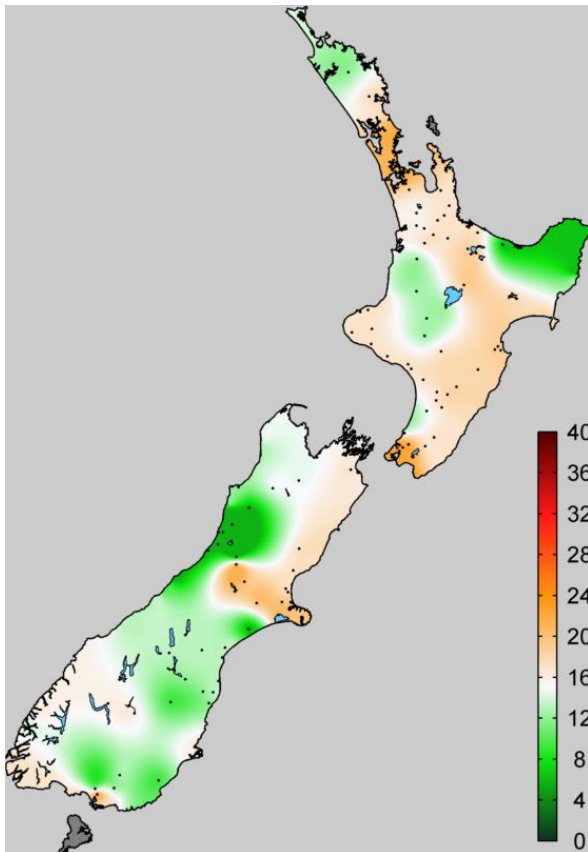
¹⁷ The upper North Island (UNI), lower North Island (LNI), upper South Island (USI) and lower South Island (LSI).

5. The current TPM produces perverse results

Transmission charges do not reflect the cost of transporting electricity from generation to loads

- 5.1 As discussed above, where practicable, transmission charges should be market-based, and if that's not possible they should be service-based and cost-reflective.
- 5.2 For example, on a first principles basis, the charges for load customers situated close to key sources of generation should be lower than for similar parties located far from such generation.
- 5.3 Figure 3 below shows the locational spread of current TPM charges. The figure shows the level of TPM charges throughout New Zealand, expressed as dollars per Mega Watt-hour (ie, \$/MWh). The charges are calculated by looking at the charges paid by each load customer divided by the amount of electricity that customer takes from the grid (ie, the MWh of electricity consumption).

Figure 3: Current TPM charges for load in \$/MWh in fully variabilised terms



- 5.4 Figure 3 shows perverse results, because charges to regions that are close to New Zealand's large generators (eg loads close to generators in the lower South Island) are sometimes higher than for regions distant from that generation.
- 5.5 For example, transmission charges are moderately higher in the Taranaki region even though those customers are very close to sources of generation. Transmission charges for the Far North appear to be considerably lower than for Auckland even though there is little generation in both regions and the Far North is further from the main sources of generation.

Transmission charges do not take into account the different service levels provided to different regions

- 5.6 Some regions receive higher transmission reliability levels than is standard for New Zealand and some regions receive lower standards. These effects are not taken into account in setting charges under the current TPM.
- 5.7 For example, the Auckland region receives premium service levels, as transmission serving the area has been built to withstand the simultaneous failure of a large generator in the region and the failure of the two largest transmission assets supplying that area. Other regions have been built so that power supply continues if one element fails, and some regions do not even have this level of redundancy.
- 5.8 Figure 3 shows that Auckland pays approximately the same transmission rates as Christchurch and Wellington, which are served by a transmission system built so that customers receive power when one element fails. The higher redundancy levels for Auckland are not reflected in higher charges to the Auckland region.
- 5.9 At the other end of the spectrum, many small and rural regions receive transmission services without any redundancy but pay similar charges as areas that have had transmission built to withstand failure of at least one element.

Low growth regions pay for upgrades to support fast growing regions

- 5.10 The current TPM results in low growth regions contributing to funding grid upgrades to support fast growing regions. For example, transmission charges have increased significantly over the past five years for most transmission customers to fund growth in the Auckland region. This wouldn't occur with a service-based charge.

Some direct consumers pay less than the variable cost of supplying them

- 5.11 Some direct consumers are not currently paying the variable cost Transpower incurs to keep transmission assets operating so it can supply interconnection services to them, such as maintenance costs. This is not consistent with a cost-reflective charge.
- 5.12 Direct consumers are able to avoid variable costs by altering their production levels or by investing in distributed generation to manage their peak demand for grid-supplied electricity.

Some direct consumers pay more than the total cost of supplying them

- 5.13 Some parties face higher transmission charges. The key issue is whether the higher charges are efficient – that is, whether they reflect higher costs of serving those parties. In the case of the New Zealand Aluminium Smelter (NZAS), the answer is arguably 'no'.
- 5.14 NZAS is located in the lower South Island to access high volumes of electricity from the Manapouri power station and to minimise expenditure on the transmission grid. Despite being relatively close to its main electricity supply, NZAS currently pays approximately \$12.40/MWh in transmission charges, which is one of the highest \$/MWh rates of all direct consumers.
- 5.15 Even though NZAS is principally serviced by assets in the lower South Island, it pays a significant portion of the cost of the entire interconnection system. After recent grid upgrades, mainly in the mid to upper North Island, NZAS's transmission charges rose steeply, even though they experienced little or no improvement in their services. Most other

direct consumers have also had to pay higher charges, but arguably they received benefits from the North Island grid upgrades.

- 5.16 If NZAS were to exit New Zealand because of an inefficient TPM, Transpower is likely to need new expenditure to transport more South Island generation to the North Island, which would lead to higher overall transmission charges.
- 5.17 Furthermore, other parties would need to meet the share of transmission costs currently paid by NZAS, around \$60m per annum. The Commerce Commission does not require Transpower to write down the value of transmission assets that are no longer useful or used. If NZAS were to exit, transmission charges to other transmission customers would be likely to increase by an average of approximately 11%.

Some generators pay zero grid charges despite receiving services from interconnection assets

- 5.18 Transpower undertook the 2013 upgrades to the Wairakei Ring in the central North Island primarily to remove export constraints so that local generators could get more power out to the broader market. The service level improvement benefited these parties, but currently they do not contribute to the costs of this upgrade.
- 5.19 Similarly, as discussed above, if NZAS exited then the grid in the lower South Island would need augmenting (assuming no changes to the HVDC) so that surplus power from the deep south could flow north, benefiting South Island generators by removing an export constraint. However, under the current TPM, South Island generators would face none of the additional charges for the upgrades.

What are the fundamental problems with the current TPM?

- 5.20 Two fundamental problems with the HVDC and interconnection charges lead to the perverse results described above
- (a) They are *not service-based*. The charges that transmission customers pay don't relate to the services they receive from particular grid circuits.
 - (b) The charges are *not cost-reflective*. They are often high when the costs of using the grid are very low, and vice versa.

Sending the wrong TPM price signals leads to poor investment decisions

- 5.21 These problems mean that the TPM is sending the wrong price signals. Grid users base their decisions on these signals, and use the grid (or avoid using the grid) in ways that then influence Transpower to propose, and the Commerce Commission to approve, poor grid investment decisions.
- 5.22 Even if the Commerce Commission had perfect information about future use of the grid, the way grid users respond to faulty price signals would lead to poor grid investment decisions. But the fundamental problems noted in paragraph 5.20 also alter what information is provided to the Commerce Commission. The current TPM provides weak financial incentives for grid users to volunteer useful information to the Commerce Commission. This makes it harder for the Commerce Commission to make good decisions about grid investment proposals from Transpower.

The current TPM is also not durable

- 5.23 The current TPM is also not durable, as evidenced by the almost constant lobbying for fundamental changes to the TPM. Poor durability creates uncertainty, potentially causing grid users to make inefficient location and investment decisions and poor operating decisions. It also leads to ongoing lobbying costs for fundamental changes to the TPM.
- 5.24 The size of the problem will continue to grow as the grid is further upgraded and as international markets for some of New Zealand's industrial consumers decline in the face of worldwide technology changes.

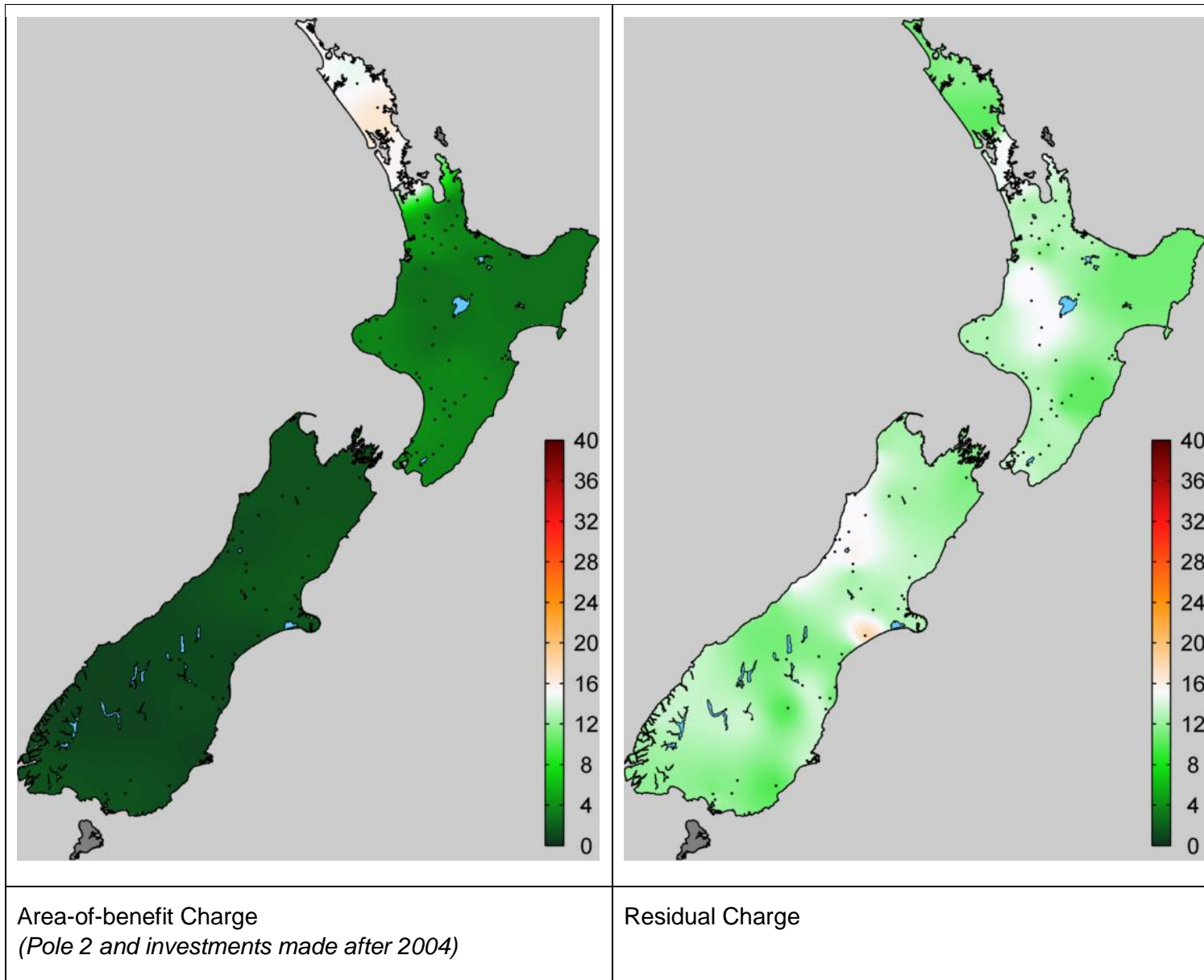
Now is a good time to address these problems

- 5.25 Now is a good time to reform the TPM. Transpower has completed major grid upgrades in the past decade and we can expect a lull before more sizeable grid investment may be required.

6. Impact of the proposal on consumers and other grid users

- 6.1 The chart below illustrates the geographic spread of transmission charges if we amend the TPM Guidelines as proposed. The left-hand-side picture shows the rate of the area-of-benefit charge and the right-hand-side shows the rate of the residual charge.

Figure 4: Expected area-of-benefit and residual charges in \$/MWh in fully variabilised terms



6.2 The following table shows how the final bill of an average residential consumer might change. The impact has been modelled for each distribution network. The modelling indicates that the proposal will only have a very modest impact on residential consumers' electricity prices.

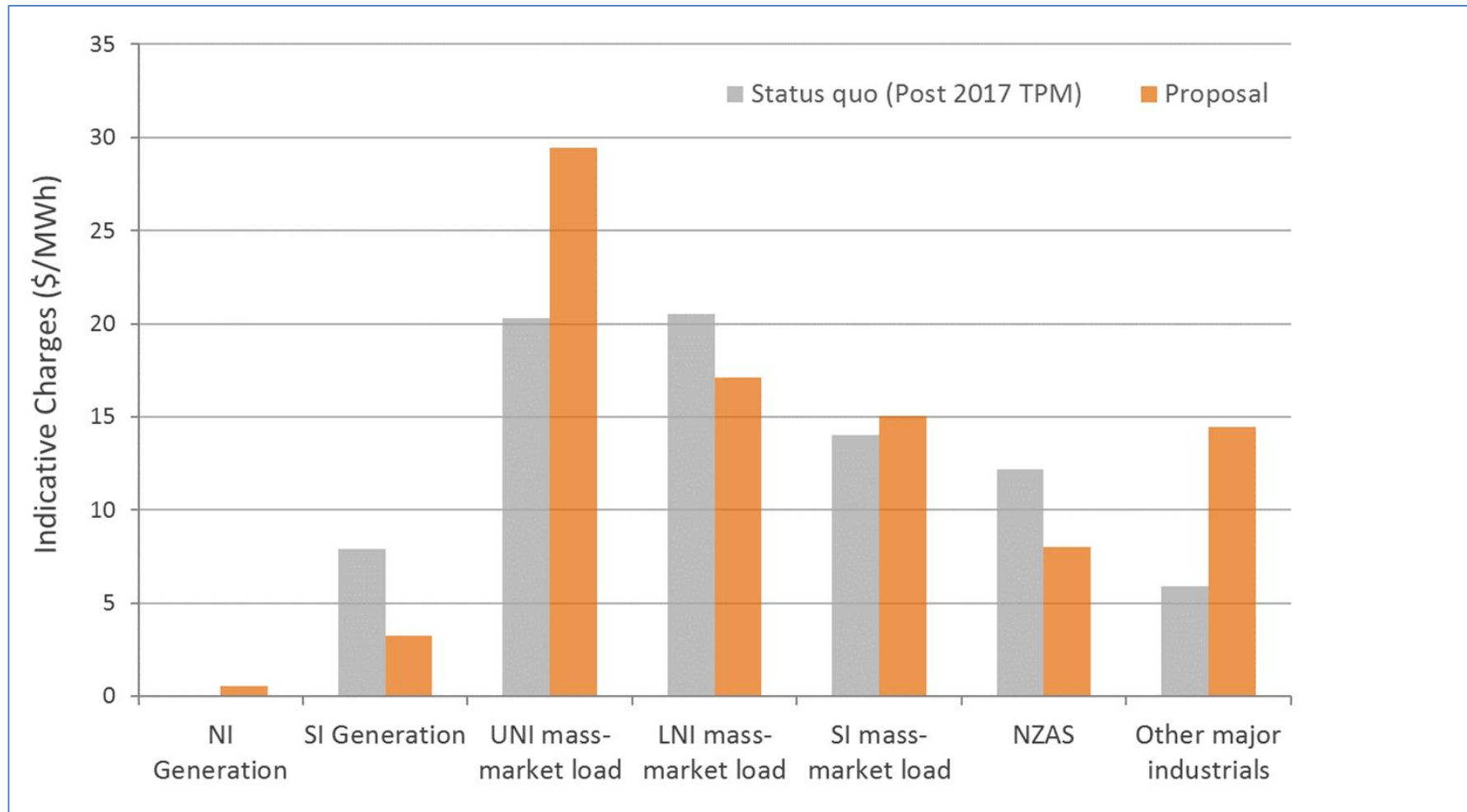
Table 1: Modelled effect of options on prices faced by residential consumers, in \$/year and as a percentage of the total retail tariff (assuming proposal results in reduced payments to distributed generation)

	Difference Between the Proposal and Status Quo as \$/year for a Typical Household	Difference Between the Proposal and Status Quo as a Proportion of the Retail Tariff
Alpine Energy	-6	-0.3%
Aurora Energy	-57	-2.9%
Buller Electricity	26	1.5%
Centralines	-29	-1.4%
Counties Power	33	1.7%
Eastland Network	-79	-4.5%
Electra	-6	-0.4%
Electricity Ashburton	102 ¹⁸	5.0%
Electricity Invercargill	-64	-3.4%
Horizon	3	0.2%
Lakeland Network	-33	-1.5%
Mainpower	-34	-1.6%
Marlborough Lines	-34	-1.6%
Network Tasman	-5	-0.3%
Network Waitaki	21	1.2%
Northpower	36	2.3%
Orion	-48	-2.3%
OtagoNet JV	-4	-0.2%
Powerco	-16	-0.9%
Scanpower	-28	-1.6%
The Lines Company	4	0.2%
The Power Company	-20	-0.9%
Top Energy	21	1.0%
Unison	-51	-2.7%
Vector	58	3.4%
Waipa Power	-10	-0.6%
WEL	-7	-0.4%
Wellington Electricity	-36	-2.1%
Westpower	49	2.7%

¹⁸ In paragraph 1.16 we state that residential consumers in the Electricity Ashburton region would face a \$117 increase per year. The \$117 increase assumes that the proposal results in no reduced payments to distributed generation, whereas the figures in Table 1 assume payments to distributed generation are removed.

6.3 Figure 5 below shows the current charges for key transmission customer groups and what they have been modelled to be charged under the proposal. We calculated this by dividing the total charge for each customer group by the group's total consumption or generation. The calculation gives us a "fully variabilised" charge (expressed in \$/MWh).

Figure 5: Modelled transmission charges in fully variabilised terms (\$/MWh) for major customer groups under the Authority's proposal relative to the 2017 status quo



Part B: Distributed generation pricing principles

7. We are proposing to remove the distributed generation pricing principles from the Code

- 7.1 In addition to our proposals for transmission pricing, we are also making a separate proposal on the pricing of distributed generation.
- 7.2 Electricity generators connected to a local distribution network are called distributed generation. The rules for setting the charges that owners of distributed generation must pay to distributors, and vice versa, are called the distributed generation pricing principles (DGPPs). The DGPPs are set out in Part 6 of the Electricity Industry Participation Code 2010 (Code).
- 7.3 We are proposing to remove the DGPPs from Part 6 of the Code.
- 7.4 We believe that separate pricing principles for distributed generation are unnecessary. For some years, the Authority has had a set of pricing principles which guide distributors in setting prices for distribution services generally. If the DGPPs are removed, distributors will be guided by these pricing principles in setting prices for distributed generation.
- 7.5 We propose to phase in the change to Part 6 of the Code. The new Code would come into effect on 1 April 2017 for distributed generation located in the Lower North Island and Lower South Island regions, and on 1 April 2018 in all other regions. A phased transition allows more time for Transpower and distributed generation owners to make agreements on distributed generation operation and payment to replace the current payment system. Distributed generation in the Lower North Island and Lower South Island is not expected to reduce transmission costs, so it makes sense to implement these changes in those regions first.

Next steps on the distributed generation pricing principles proposal

- 7.6 The next steps are as follows:
- (a) we will publish the submissions made on the Review of Part 6 distributed generation pricing principles
 - (b) we will consider submissions.
- 7.7 If, after considering submissions, we decide to implement this proposal, we are aiming to have the first phase implemented before 1 April 2017.

8. The distributed generation proposal offers long-term benefits to consumers

- 8.1 Removing the DGPPs from Part 6 will promote the long-term benefits of consumers by reducing costs and promoting more efficient operation and investment decisions for distributed generation owners and the broader electricity sector. Consumers will not pay more than is necessary for electricity and therefore will not have to change their decisions about how much electricity to use.
- 8.2 We also expect positive effects on competition. It would put distributed generation owners on a more level 'playing field' with generators connected to the transmission grid, and this may encourage new investment in generators connected to the transmission grid.

Distributed generators will continue to operate in regional areas of New Zealand where that would be the most efficient solution. We do not expect the proposal to have any adverse effects on the reliability of the electricity system. We do not expect that many (if any) distributed generators would shut down as a result of our proposal.

- 8.3 Consumers will benefit if our proposal is adopted, and owners of distributed generation will be worse off. The financial benefit to consumers over the next 15 years is in the range of \$46 million to \$325 million (in today's dollars). This gross benefit to consumers is a wealth transfer that is outside the Authority's statutory objective and is included here as background information.
- 8.4 We do not think that our proposal will have any negative environmental outcomes, if implemented. A large and increasing proportion of generation in New Zealand is renewable (currently between 70% and 80%). This applies to generators connected to the transmission grid as well as to distributed generation. Further, about 95% of all new grid-connected generation and distributed generation proposals are renewable. The Emissions Trading Scheme in principle will continue to give an advantage to renewable generation. As environmental outcomes are outside the Authority's statutory objective, this discussion is included as background information for other policy-makers and stakeholders to consider.

9. Background on the distributed generation pricing principles

- 9.1 Distributors provide network services to distributed generation owners. Distributed generation owners use their own network connection to inject electricity into the distribution network and earn revenue by selling electricity.
- 9.2 Distributed generation owners can also provide network support services to networks. Distributed generation can, in some circumstances, reduce the capital and operating costs of distribution and transmission systems. For example, a transmission circuit that is frequently operating at full capacity may need to be upgraded to a higher capacity to reliably supply a town. This can be costly. However, if distributed generation supplies electricity to the town—through the distribution network—then less electricity needs to be imported to the town across the transmission grid. This means the grid upgrade can be avoided or postponed, avoiding significant costs for the distributor (and ultimately for consumers).
- 9.3 Part 6 of the Code includes a set of regulated terms to use between distributors and distributed generation owners if they do not negotiate their own connection agreement. Where the regulated terms apply, charges must be consistent with the DGPP.

10. Problems with the current distributed generation pricing principles

- 10.1 The current DGPPs creates two problems:

- (a) The DGPPs require that distributed generation owners pay the distributor no more than the incremental cost of being connected to the local distribution network.¹⁹ This means distributed generation owners are not required to pay a share of common network costs, such as the distributor's overhead costs. Instead, electricity

¹⁹ Incremental costs (IC) are the additional costs of providing one more network customer with network services, or providing existing customers with additional services. In broad terms, common costs are costs that are the same regardless of whether more customers are added to the network or regardless of how much electricity is flowing through the network.

consumers (which include commercial and industrial consumers) have to pay their own share of common costs and the distributed generation owner's share.

- (b) The DGPPs require distributors to pay distributed generation owners for the network support services they provide. The DGPPs provide for distributors to make payments equal to the transmission charges that the distributor can avoid as a result of the distributed generation. These are called avoided cost of transmission (ACOT) payments.

These ACOT payments are supposed to reward distributed generation owners when they reduce the capital or operating costs of the transmission grid. However, they do not achieve their intended objective. Distributed generation often does not actually reduce transmission network costs, even when it does reduce the transmission charges that the distributor pays.

ACOT payments have grown rapidly in the last eight years, and very little of this growth is likely to have reduced transmission costs. As a result, consumers are likely paying electricity bills that are higher by around \$25-\$35 million per annum without receiving a benefit in return.

- 10.2 Both of these problems are likely to cause wasteful activity. That is, they will encourage distributed generation owners to operate their distributed generation, or build new distributed generation,²⁰ when that is not the lowest cost way to provide electricity.
- 10.3 Removing the DGPPs from Part 6 of the Code would remove the requirement (in the DGPPs) that distributed generators pay the distributor no more than the incremental cost of being connected to the local distribution network. This would allow distributors to set prices that do not create wasteful incentives for distributed generation or consumers.
- 10.4 Removing the DGPPs would also solve the ACOT payments issue. If the DGPPs are removed, Transpower would decide whether to make payments to distributed generation owners for reducing transmission costs. As the owner of the transmission grid, Transpower is best placed to know whether a distributed generation operation is actually reducing the costs of the grid (and by how much). Transpower should pay for distributed generation if—and only if—it reduces transmission costs. As a result, distributed generation which does not reduce transmission costs will not be encouraged and distributed generation which does reduce costs will be encouraged.

²⁰ The ACOT problem also applies to generators that are “notionally embedded”. Notionally embedded generators are entitled under a contract to receive payments equivalent to ACOT payments.