

19 February 2019

Jean-Pierre de Raad  
Acting Network Pricing Manager  
Electricity Authority  
Wellington

By email: [submissions@ea.govt.nz](mailto:submissions@ea.govt.nz)

Dear Jean-Pierre,

## More efficient distribution prices – What do they look like?

We welcome the opportunity to respond to the Electricity Authority's (the Authority's) consultation paper "More efficient distribution prices - What do they look like?" dated 11 December 2019.

Transpower's prices are a material input into distribution prices, and we have a strong long-term interest in ensuring network pricing sends efficient signals to promote efficient investment in and utilisation of transmission and distribution networks (and other supply chain elements) for cost effective and competitive services into the future.

Our views on network pricing in this submission are consistent with past submission content – we provide several relevant previous submissions in Appendix 1. We discuss the following areas:

- The priorities and principles for network pricing as we submitted to Hikohiko Te Uira, the Electricity Price Review's First Report in October 2018, intended to initiate discussion;
- The opportunity to draw on OFGEM's work on network pricing reform;
- The Authority has proposed to remove the pricing principle "prices signal the impact of additional usage on future investment costs":
  - we do not support its removal – in our view it is needed now more than ever;
  - the views expressed by the Authority are a significant shift from its previous views; and
  - cross-sector consistency and a coherent approach to electricity network pricing are vital;
- The importance on understanding impacts across all consumers (not just the average consumer) and that acceptance by consumers and stakeholders will be critical for a successful transition; and
- A role for policy development assistance by an Expert Advisory Panel.

Appendix 2 provides our responses to the consultation questions.

## Principles we consider appropriate for network pricing

Our submission to the Electricity Price Review: Hikohiko Te Uira First Report contained “our draft thinking” on useful (draft) network pricing principles as follows.<sup>1</sup>

*“Investment and price settings*

- *Network pricing (both distribution and transmission) should:*
  - *be simple, understandable to a wide range of sector participants, implementable and operable with limited discretion in a way that avoids the sector being held back by disputes;*
  - *be cost-based and sensitive to the importance of signalling peak network usage, as this will promote greater utilisation of existing assets by flattening demand and deterring peak demand growth, delaying or avoiding the need for further network investment;*
  - *introduce change incrementally, in a way that avoids price shocks, is sensitive to the impact on vulnerable regions or groups of consumers, and limits the potential for unintended consequences;*
  - *be aimed at securing wide-spread support for any change, including by reference to a clear and complete cost-benefit analysis;*
  - *be focused on the future, and the pathway of generation and network investment implied by New Zealand’s climate change objectives including enabling new technologies that will change the role and consumption patterns of consumers.*
- *Reform of distribution pricing that is sensitive to alignment with the Transmission Pricing Methodology (TPM), the importance of signalling peak network usage, and the way that new technology will change the role and consumption behaviour of consumers.*
- *Resolution of the TPM reform process within two years and in a way that clearly provides for the costs of the interconnected grid to be [socialised or personalised].*
- *Change to the investment framework to allow proactive transmission network investment where appropriate (for example, facilitating the pipeline of generation investment required by New Zealand’s climate change response).”<sup>2</sup>*

We recommend that any changes to the distribution pricing principles are sensitive to alignment with the principles for the Transmission Pricing Methodology (TPM), the importance of signalling peak network usage, and the way that new technology will change the role and consumption behaviour of consumers.

## Drawing on the work of UK regulator Ofgem

The Authority has referenced Ofgem’s<sup>3</sup> pricing reviews in the context of network pricing reform here. We support the Authority referring to comparable and leading international regulatory reform processes for pricing change. We present below the principles that Ofgem is applying to its *options analysis* for its two concurrent reviews on network pricing.

Ofgem recognises the “energy system is going through a radical transformation, with new technologies potentially becoming more widespread, including solar PV, electricity storage, electric

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<sup>1</sup> Transpower [submission](#) to Electricity Price Review : Hikohiko Te Uira, First Report, October 2018.

<sup>2</sup> Ibid, page 25.

<sup>3</sup> [Ofgem](#) is the office of the gas and electricity market (the regulator) in the United Kingdom.

vehicles and heat pumps. Making the best use of network capacity and having effective signals on how users can create costs and benefits on the networks is critical to the development of a flexible and dynamic future energy system, which can accommodate these new technologies and facilitate the decarbonisation of the energy system in an efficient way.”<sup>4</sup>

Table 1 presents OFGEM’s review principles; in both reviews the principles include implementation objectives (‘proportionate and practical’) as well as efficiency objectives. We also note OFGEM’s attention to (i) articulating what is meant by fairness under its targeted charging review, and (ii) application of a consultative process focussed on the importance of ensuring stakeholder and consumer acceptance.

**Table 1 OFGEM's options assessment principles**

<a href="#">Targeted charging review</a> (residual allocation) principles	<a href="#">Access and forward-looking charges</a> review principles
<p>Reducing harmful distortions; such as inefficient investment in generation for the purposes of reducing residual charges;</p> <p>Fairness*; particularly with respect to improving the fairness of residual charges, and primarily for domestic users; and</p> <p>Proportionality and practical considerations; achieving changes in a proportionate and practical manner.</p>	<p>Arrangements support efficient use and development of network capacity</p> <p>Arrangements reflect the needs of consumers as appropriate for an essential service</p> <p>Any changes are practical and proportionate</p>

\*encompasses: equity and equality, simplicity, transparency, justifiability and predictability (refer [TCR principles](#) document)

We recommend pricing reform for New Zealand is viewed with an implementation lens as well as an efficiency lens, and follows a consultative process focussed on achieving stakeholder and consumer acceptance.

## **We do not support removal of the pricing principle “prices signal the impact of additional usage on future investment costs”**

We do not support removal of the pricing principle that network “Prices are to signal the economic costs of service provision by: ... signalling, to the extent practicable, the impact of additional usage on future investment costs”. We consider this is the most important principle for dealing with the Authority’s concern that current standard distribution pricing practices inefficiently reward investment in solar PV and other behind-the-meter technologies. Our views on peak pricing have been well canvassed in various submissions.<sup>5</sup>

As reflected in our strategic papers *Transmission Tomorrow* (2016) and *Te Mauri Hiko – Energy Futures* (2018), we see a much greater future risk that if network investment is made earlier than necessary it could become obsolete. In our view, the principle that prices signal future investment

<sup>4</sup> OFGEM Significant Code review launch [statement](#) December 2018.

<sup>5</sup> Most recently in our response to a request from the Authority offering “the opportunity to provide evidence as to whether or not the removal of the Regional Coincident Peak Demand (RCPD) charge [from the TPM] would have an adverse effect on the ability to meet peak demand”: [The role of Peak Pricing for Transmission](#), 2 November 2018. Each of the other submissions attached as part of this submission are also relevant – refer to list under Appendix.

costs is needed more than ever: “As consumers’ demand for [network] services evolves we see a much greater risk of investing in assets that are required only for a decade or two (maybe less) of their perhaps four, five, or more decade physical lives. The faster peak demand grows in the short or medium term, the higher the risk [network owners] invest in new assets that become obsolete but must still be paid for.”<sup>6</sup>

The Authority has previously been clear the principle it now wants to amend is consistent with “service-based” pricing: “Service-based distribution prices encourage consumers to make decisions that not only benefit themselves, but also benefit other consumers using the distribution network (e.g., deferred or avoided network investment)”<sup>7</sup> and “prevailing distribution prices are not service-based. They do not signal to network users the cost of new capacity”.<sup>8</sup>

Further the Authority has stated “Distribution prices should ... encourage consumers to take actions that reduce current or future network costs (e.g., draw electricity for the household from battery storage systems during a period of network congestion, or recharge electric vehicles off-peak instead of during a period of network congestion)”.<sup>9</sup> We agree, including that “This does not mean that prices must be exactly equal to long run marginal cost”.<sup>10</sup> We support the Authority’s previous more economically orthodox assessment of LRMC pricing in the LRMC Working Paper.<sup>11</sup>

Analysis we recently provided to the Authority<sup>12</sup> highlights that even imperfect pricing signals (which may not fully or exactly match future investment costs in pure economic terms), can offer substantial benefits in terms of investment deferral or avoidance, meaning lower prices over time, and more efficient network usage (increased load factors). The analysis demonstrates these benefits even with relatively inelastic demand for electricity services.

We recommend retaining the principle “Prices are to signal the economic costs of service provision by: ... signalling, to the extent practicable, the impact of additional usage on future investment costs” because of its vital role in managing costs to consumers into the future. To do so would be consistent with previous views published by the Authority.

## Cross-sector consistency is important and coherent network pricing is vital

We have previously commented to the Commerce Commission (the Commission) that its Airport Pricing Principles are industry agnostic, and equally valid for electricity distribution and transmission pricing.<sup>13</sup> In our view the proposed changes to the Distribution Pricing Principles (DPPs) would reduce cross-sector consistency, without it being clear that the reasons reflect industry-specific factors.

We consider both efficient use of and efficient investment in New Zealand electricity networks depends on the effectiveness of price signals to end users of the networks - across both distribution

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<sup>6</sup> Transpower, [The role of Peak Pricing for Transmission](#), 2 November 2018, page 4.

<sup>7</sup> Electricity Authority, [Consultation Paper](#), Implications of evolving technologies for pricing of distribution services, 3 November 2015, page F.

<sup>8</sup> Ibid page G.

<sup>9</sup> Ibid, page G.

<sup>10</sup> Ibid, paragraph 7.1.1.

<sup>11</sup> Transpower [submission](#) TPM 2nd issues paper, supplementary consultation, February 2017, Appendix C: Electricity Authority LRMC Working Paper.

<sup>12</sup> Transpower, [The role of peak pricing for transmission](#), 2 November 2018.

<sup>13</sup> Transpower [submission](#) Auckland International Airport’s pricing decisions, 29 May 2018.

and transmission pricing. It is important to ensure a coherent and joined-up approach to electricity network (distribution plus transmission) pricing.<sup>14</sup>

If the TPM doesn't signal the impact of additional usage on future investment costs then, even if distribution pricing does, the signal will only be a partial signal (limited to the distribution component of future network (distribution plus transmission) investment costs).

We recommend a consistent, cross-sector approach to network pricing, where differences in approach reflect genuine industry-specific factors, and a coherent and joined up approach to electricity network pricing across transmission and distribution.

## Understanding impacts on consumers (not just the 'average' consumer)

Modelling for the Electricity Networks Association (ENA) of the impact of consumers of different price tariff designs shows price impacts for individual consumers can vary widely around the average, even within demographic bands. And often those least able to pay are worst affected. This trend poses a clear risk to successful price reform, which will hinge on its acceptance by consumers. For pricing reform to be durable, consumers and stakeholders need to understand and buy-in to change. In the near term, adopting pragmatic, practical solutions that are targeted at known current problems, directionally-efficient and quick to implement may be more valuable than striving for a more theoretically correct or novel approach to pricing. We also consider standardisation of tariff structures and terminology between network companies would help facilitate the transition to the benefit of consumers.

Successful price reform will hinge on its acceptance by consumers. We consider the industry and regulators should work together to deliver near-term distribution pricing reform by focusing on simple, pragmatic, directionally-efficient and quick to implement new tariffs targeted at known current problems.

## An Expert Advisory Panel could assist the Authority and electricity networks

OFGEM commonly uses Expert Advisory Panels to peer review its work and is doing so for its current reviews to reform network pricing for the future (the drivers for reform are similar to those here). The Commission also regularly uses international experts to peer review its work and submissions. Most recently, the Commission established a three-member Expert Advisory Panel for the development of the new fibre regulatory regime. The Panel has been positively received by stakeholders.

We consider an Expert Advisory Panel, made up of well-respected, international experts, could assist with the network (distribution and transmission) pricing issues.

Finally, we agree that distribution pricing could more accurately reflect costs, but success depends on the cooperation of industry participants, regulators and government – and acceptance. For pricing reform to be durable, consumers and stakeholders need to understand and buy-in to change.

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<sup>14</sup> Our views in more detail are in our [submission](#) to the ENA on distribution pricing reform, and our last [submission](#) to the Authority on distribution pricing: Distribution Pricing: New Pricing Options for Electricity Distributors, 23 Dec 2016 and Distribution pricing review, 2 Feb 2016, App E.

Well managed and accepted price reform will help realise tremendous benefits for this sector and New Zealand as the economics of new technologies improve, including for electric vehicles, solar PV and batteries.

Yours sincerely

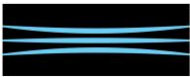
A handwritten signature in blue ink, appearing to read 'Rebecca Osborne', with a stylized, cursive script.

Rebecca Osborne  
**Regulatory Affairs and Pricing Manager**

## Appendix 1: Supporting material for our submission

Our views on network pricing have been well canvassed. In this Appendix we list and reproduce the following already-published Transpower [submissions](#) and reports, which remain relevant.

1. Electricity Authority, Distribution pricing review, 2 February 2016, Appendix E;
2. Electricity Networks Association (ENA), Distribution Pricing: New Pricing Options for Electricity Distributors, 23 December 2016;
3. Electricity Authority, TPM 2nd issues paper, supplementary consultation, February 2017, Appendix C: Electricity Authority LRMC Working Paper;
4. Commerce Commission, Auckland International Airport's pricing decisions, 29 May 2018; and
5. Response to Electricity Authority request, [The role of peak pricing for transmission](#), 2 November 2018.



2 February 2016

John Rampton  
Electricity Authority

**By email:** [submissions@ea.govt.nz](mailto:submissions@ea.govt.nz)

Dear John

## Distribution pricing review

We appreciate the opportunity to comment on the Authority's electricity distribution pricing methodologies (EDPM) consultation, *Implications of evolving technologies for the pricing of distribution services*, published 3<sup>rd</sup> November 2015.

The publication of the EDPM consultation paper is a positive step that brings focus to an issue of strategic importance for the sector. We consider an evolution in the design of distribution prices that can be reflected in retail price offerings is desirable for the long-term health of the electricity sector, as well as for the achievement of the Authority's statutory objective. This work should be a top priority with more direct stakeholder engagement, possibly via workshops or Advisory Group.

As the Authority identifies in the EDPM consultation, distribution tariffs have an important influence on retail pricing. In addition to basic tariff design (the focus of the EDPM consultation), the number and consistency of methodologies across the 29 distribution networks and the volume of individual tariffs are also influential factors.

In this submission we discuss the following points.

1. **The pricing problem.** We agree that if prices reflect the cost of providing the service then more efficient consumption and investment decisions will be enabled and encouraged.

Additional focus is needed on enduring concerns about the consistency and number of price methodologies which can increase cost, dampen competition and deter retail price innovation.<sup>1</sup>

2. **Transition.** The challenge of developing and transitioning to more cost-reflective distribution (and in turn retail) price structures should not be underestimated.

We consider a pan-sector 'project' involving distributors, retailers, regulators and consumers, amongst others, would be desirable. The Authority also has an important enabling and supporting role in facilitating pricing reform.<sup>2</sup>

3. **Convergence.** We recognise the EDPM review has been in train since 2012/13 but this is the first substantive industry engagement. It arrives at a time of continuing policy debate on transmission and distributed generation pricing (and more recently on use of system agreements) and when the Commerce Commission is considering related issues about the impact of emerging technology in the context of its input methodologies review.

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<sup>1</sup> Including to limit the ability of retailers to translate distribution price signals into retail prices.

<sup>2</sup> For example, to provide policy guidance and preferably to define 'safe harbours' in relation application of low fixed charge regulations to de-risk price reform by distributors and retailers; and, to provide a regulatory back stop to help overcome inertia and provide confidence that price reform will occur.



We encourage the Authority to detail the steps it is taking to ensure policy coherency across all these related and converging initiatives.

### The distribution pricing ‘problem’

We consider there is a pressing need to simplify distribution pricing and to ensure those prices better reflect the cost of the services being provided. The need for reform is in part driven by the challenges and opportunities identified in the paper (we agree that emerging technologies will be “transformational”) but also by enduring concerns about the consistency and number of price methodologies which increase cost, dampen competition and deter retail price innovation.

We are concerned that some of the analysis and messaging of consultation materials leads to a view of technological winners and losers. We consider that there is likely to be an interrelationship between investment in EV and demand response, including batteries and investment in solar and that this materially affects the outcome of any efficiency analysis. For example, an end-user that invests in solar may be more likely to also invest in EVs and batteries, and vice versa. If an end-user invests in batteries because they are investing in solar then their reduction in peak usage can be attributed to solar.<sup>3</sup>

Ideally the analysis would be technologically-agnostic but given it focused on solar PV it needed to recognise the potential interdependencies with the other self-supply technologies such as battery-storage and electric vehicles, as well as understand and quantify the various benefits of solar to consumers. Further analysis would also distinguish between distribution pricing and other components of retail tariffs that create a wedge between the marginal cost of electricity generation and variable charges.

Network pricing should send pricing signals that are ‘useful and usable’. Clear and simple tariffs that are straight forward for retailers to manage will likely better enable and encourage the transfer of price signals to consumers. Consistent with this, we agree the Authority that “It is not necessary for distributors to set prices that perfectly reflect the cost of the services provided”.

It should be recognised that tariff complexity and the number of different tariffs can impact on the costs to retailers of entering into, and competing in, any particular EDB network area. The smaller the network area (in terms of customer numbers) the smaller the number of potential customers these costs can be recovered from. This has been raised by retailers as a potential barrier to competition in the past, and a reason why there are different levels of competition (measured, for example, by the incumbent retailer market share or the number of retailers in any given network).

Further, if tariffs are too complicated, or too granular, retailers may respond by re-bundling (averaging) the tariffs into a smaller set. There needs to be an understanding of the level of complexity and transaction costs retailers are willing to (or can cost effectively) incur in setting retail tariffs – particularly, on networks with a small number of potential customers.

### Transition to sustainable pricing structures

It does not matter whether a ‘too high’ volumetric charge is attributable to transmission, distribution, generation or retail. If it is reflected in retail tariffs it will have the same impact – including over-incentivising investment or activity – be it energy efficiency or substitutes e.g. gas supply or solar. We recognise “there is no single ‘right’ pricing structure for all distributors because each distributor faces different circumstances”, and a ‘one size fits all’ approach to ‘cost-reflective’ pricing will not necessarily be best”. However, the recovery of the fixed costs of distribution

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<sup>3</sup> Further, if electricity distribution pricing over-encourages investment in solar then it will also over-encourage investment, or consumption behaviour, that results in reduction in electricity consumption more generally e.g. take-up of gas and choice of higher energy efficiency rated appliances.

networks via volumetric charges appears to be a fundamental structural problem that is common to most if not all distributors that needs to be unwound to a greater or lesser extent.

We agree that distribution companies should have natural incentives to reform pricing structures and consider the Authority has an important role to play in enabling and supporting this reform. For example:

- Providing policy guidance and preferably to define ‘safe harbours’ in relation to the application of low fixed charge regulations to de-risk price reform by distributors and
- Providing a regulatory back-stop to help overcome inertia and provide confidence that price reform will occur.

We note that the Australian Energy Market Commission (AEMC) has already created rules (effective 1 December 2014) that require distribution businesses to develop network prices that are cost-reflective and send efficient pricing signals to consumers<sup>4</sup>

- [As the Authority identifies] clarification of the role of the Code’s pricing principles and their meaning, including how to manage conflicts in the principles.

The Authority can also play a valuable coordinating role, possibly sponsoring an industry working group or establishing an Advisory Group (as section 21 of the Electricity Industry Act envisages for reforms of this nature).

With any potential tariff reforms it is important to demonstrate how consumers will receive clear and tangible benefits from reform (we thought the summary brochure to this consultation paper was a good example of how potentially complex matter can be communicated to a non-expert audience). We note use of a range of independent research and summary communication in the examination of pricing and technology issues for distribution networks in Australia. By way of illustration, work conducted by Energeia, for the Energy Networks Association in Australia, “found a potential benefit of \$17.7 billion in savings in investment in infrastructure over the next twenty years, resulting in an annual saving on average energy bills of \$250 by the end of the period”.

We do not underestimate potential opposition to reform; for example where:

- where the need for and benefits of reform are ill-defined or not effectively understood by consumers
- where the information needed to respond to new tariffs is not available to consumers or able to be acted upon
- where consumers have invested large sums of money, in good faith, on the basis of current pricing arrangements. [As experienced with changes to feed-in-tariffs (FiTs) in Australia and the UK, payments which have been drastically scaled back as demand for the technology has increase. There has been a lot of predictable objection to the reduction in FiT rates from people that have invested in solar).

The difficulty of reform is increased by negative press and can be increased exponentially by major failings. We consider that this pushes strongly towards a carefully planned and coordinated transition effort that draws on the relevant stakeholder constituency, identified and addresses key challenges before they reach the headlines.

## Network pricing coherence

While the Authority is presently treating the distribution pricing (EDPM), low fixed charge regulations, distributed generation pricing (ACOT) and the TPM review as discreet work streams, it seems axiomatic that the underpinning policy and pricing theory fit together in a coherent manner.

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<sup>4</sup> <http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements>

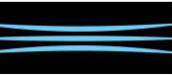
It is not always obvious that this is the case and we support clarification by the Authority of how it is ensuring policy coherence across these related and converging initiatives.

Finally, although we are not directly impacted by reform to distribution pricing, we have a strong long-term interest in ensuring consumers receive efficient price signals. This will promote efficient utilisation of transmission and distribution networks (and other supply chain elements) and improve the cost effectiveness and competitiveness of the services we collectively provide.

Yours sincerely

A handwritten signature in black ink, appearing to be 'JK' followed by a long horizontal line.

Jeremy Cain  
**Regulatory Affairs & Pricing Manager**



23 December 2016

Graeme Peters  
Chief Executive  
Electricity Networks Association (ENA)  
Wellington

By email: [graeme.peters@ena.org.nz](mailto:graeme.peters@ena.org.nz)

Dear Graeme

## Distribution Pricing: New Pricing Options for Electricity Distributors

We appreciate the opportunity to respond to ENA's discussion paper "New Pricing Options for Electricity Distributors", November 2016.

Our principal comments are provided in the main body of this submission, while responses to the consultation questions are included in the Appendix. Our submission to the Electricity Authority, "Distribution pricing review", 2 February 2016,<sup>1</sup> should also be treated as part of this submission.

### Overview

In this submission we make the following key points:

1. **This is a valuable contribution to distribution pricing reform:** containing helpful information and analysis. The next step is planning for a timely and smooth transition to new pricing models.
2. **We encourage a broader role for the ENA:** To aid that transition, developing standardised tariff options, communications and planning tools and supporting networks' actual transitions.
3. **Direct involvement from regulators and government:** Possibly via a pan-industry steering, will provide stakeholder confidence, help ensure alignment and provide a 'clearing house' for difficult or multilateral issues.
4. **Coherence between network pricing is desirable:** Price signals will be more efficient and actionable if transmission, distribution pricing and derivatives<sup>2</sup> are coherent and complimentary.
5. **A tremendous opportunity the sector, and economy:** well managed price reform will help realise tremendous benefits for this sector and New Zealand; but success depends on the cooperation of industry participants, regulators and government.

We provide some introductory comments then expand on these points below.

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<sup>1</sup> Available at: <http://www.ea.govt.nz/dmsdocument/20467>

<sup>2</sup> Such as distributed generation pricing principles and price signals to other potentially responsive parties.

## Introduction

We found the discussion paper very accessible and easy to read. It has a clear focus on managing network costs and investment requirements, and avoided getting bogged down by economic theory or jargon. As with the Electricity Authority's distribution pricing consultation last year, the provision of 'user-friendly' summary documents is a useful addition. Not all stakeholders will want or need to get into the full detail of a lengthy discussion paper.

Although we are not directly impacted by reform to distribution pricing, we have a strong long-term interest in ensuring consumers receive efficient price signals. This will promote efficient utilisation of transmission and distribution networks (and other supply chain elements) and improve the cost effectiveness and competitiveness of the services we collectively provide. In addition, the bulk of our own costs are recovered via distributors, through distribution charges.

## Process and decision-making framework

This consultation is a valuable contribution to distribution pricing reform. It contains helpful information and analysis.

We agree with ENA's views on the importance of getting process right, including that "A robust process for developing new pricing structures will involve several iterations of consultation ... Although this takes time it is important for all electricity consumers that we get our pricing right",<sup>3</sup> and "effective consultation" requires approaching the matter "with an open mind", and being "prepared to change or even start a process afresh".<sup>4</sup> This is at the forefront of our mind as we do our planning for a process to convert potential new TPM Guidelines, next year, into a new TPM.

We also agree "Future pricing of distribution services should be:

1. Cost-reflective – fair and free of inefficiencies and cross-subsidies between consumers as far as possible
2. Service-based – reflect the services being provided
3. Actionable – provide price signals that consumers can choose to respond to
4. Durable/effective in the long term – independent of market, technology and policy changes
5. Compliant – meet regulatory requirements
6. Simple – transparent and easy to understand
7. Stable and predictable – avoid volatility"<sup>5</sup>
8. These are sound principles for any form of network pricing.

More specifically, we agree:

- consumer buy-in is important for durability. As ENA note what might be the theoretically-efficient pricing methodology, may not be the best and consumer buy-in is needed;
- in terms of prices that are "Actionable" our view is that "Network pricing should send pricing signals that are 'useful and usable'. Clear and simple tariffs that are straight forward for retailers to manage will likely better enable and encourage the transfer of price signals to consumers. Consistent with this, we agree with the Authority that "It is not necessary for distributors to set prices that perfectly reflect the cost of the services provided"<sup>6</sup>;

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<sup>3</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 3.

<sup>4</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 29.

<sup>5</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 3.

<sup>6</sup> Transpower, submission to the Electricity Authority, Distribution pricing review, 2 February 2016.

- there can be trade-offs between the principles, including “between pricing that is cost-reflective but is still simple and understandable”, and that “It is important to clearly identify and assess trade-offs of this type”<sup>7</sup>. We consider there is a pressing need to simplify distribution pricing;
- consistent with this, ENA has previously noted: “Given that consumers prefer simple flat rate prices, it may be that competitive pressures will reward retailers that retain flat rate pricing structures even if distributors move to introduce more cost-reflective charges”.<sup>8</sup> If consumers prefer simpler tariffs, even if it means they “forgo possible cost savings”,<sup>9</sup> then this may be the most efficient outcome;
- in terms of trade-offs, we also agree cost reflectivity should not be given “absolute priority ... over stability and certainty”,<sup>10</sup> and
- pricing stability is important if price signals are to be effective: We agree “Prices for electricity need to be stable in the long term to provide the right signals to consumers about their investment and consumption decisions”.<sup>11</sup>

We also agree that “The optimal pricing method may vary by distribution network because of the unique characteristics of each distributor’s environment”.<sup>12</sup> For example, consistent with comments the Electricity Authority has made,<sup>13</sup> there may be little value in adopting TOU or peak-usage prices in network areas where there is ample distribution and transmission network capacity to meet demand, and limited or no need for capacity upgrades e.g. the LRMC of both distribution and transmission is low or zero. The circumstances could be very different for an EDB in a region facing rapid growth and substantial expected investment needs.

### Impact of emerging or evolving technology

The electricity sector is transitioning from a world where demand for electricity had predictably grown with population and GDP, to one where demand is less certain. This was evident from submissions made by EDBs on the demand growth assumptions the Commission applied to the 2015 DPP draft determination, and in relation to the Commission’s Input Methodologies review, including consideration of price versus revenue caps and accelerated depreciation.

While there has been a lot of debate about the regulatory implications of emerging technology, there has been less debate that it has the potential to mean investments made today won’t necessarily be needed, in the same way, in the future. We consider that emerging technology provides potentially large opportunities, but also risks and the key to managing these is sensible price signals.

One of the implications of this, in our view, is that it strengthens the justification for the types of LRMC-based peak-usage, capacity or time-of-use pricing advocated in the ENA discussion paper. Emerging technology, whether thought of as a material change in circumstances or not, has implications for optimal pricing at all levels of the electricity supply chain.

### Distribution and transmission pricing should operate in a joined up and complementary manner

<sup>7</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 4.

<sup>8</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, page 15.

<sup>9</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, page 16.

<sup>10</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, paragraph 46.

<sup>11</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 6.

<sup>12</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, pages 3 and 4

<sup>13</sup> Electricity Authority, Implications of Evolving Technologies for Distribution Pricing, September 2015, page F.

In our view, the justification ENA has provided for LRMC-based peak-usage charges, and the like, are equally valid for transmission. An end-user making decisions about whether to consume peak or off-peak should face price signals which reflect the cost of both the distribution and transmission networks, with distribution and transmission pricing complementing each other. Our position is reinforced by the data ENA references which show a strong correlation between transmission and distribution network peak demand periods.<sup>14</sup>

The types of tariff reform ENA is considering could complement and support the approach to peak-usage pricing currently in the TPM with RCPD charges, and extend the extent to which EDBs reflect the RCPD peak-usage charges in their own prices. RCPD charges are, for example, a component of Vector’s time-of-use (TOU) tariffs, but use of TOU or peak-usage pricing is not as prevalent amongst EDBs as the current ENA consultation signals it could be in the future.

This indicates the potential for EDB TOU tariffs and current TPM RCPD (or alternative LRMC-based peak-usage charges) to work in a complementary and self-reinforcing manner.

The views ENA express about the link between cost-reflectivity, the role of pricing in managing future investment requirements, and how LRMC-based pricing promotes dynamic efficiency, reflect the same kind of reasoning which sits behind our views on transmission pricing. We agree, for example, with the following statements in the ENA discussion paper:

<ul style="list-style-type: none"> <li>• <b>Link between cost-reflectivity and peak-usage pricing</b></li> </ul>	<p>“The types of pricing that best reflect costs will signal the “critical peaks” which determine network investments. These peaks often occur on the coldest days of the year, for example, when consumers’ use of electricity for heating pushes demand to its highest.</p> <p>“Pricing according to critical peaks would reflect cost drivers. But most consumers may not understand or like this form of pricing. The need for pricing that reflects critical peaks will depend on how congested the distribution network is. For example, distributors with significant excess network capacity may not need to give consumers a strong peak pricing signal.</p> <p>“Several types of pricing indicate when network peaks occur or are likely to occur, so that consumers can choose to respond by shifting their use and receive the reward of lower off-peak pricing.”<sup>15</sup></p>
<ul style="list-style-type: none"> <li>• <b>Role of pricing in managing future investment requirements</b></li> </ul>	<p>“It is largely ... peaks in demand that determine the required capacity of the lines’ network. Networks have to be built with the capability of reliably supplying consumers with the electricity they require for those few hours per day when demand is at its highest ... it is this peak capacity requirement, rather than the amount of energy consumed, that largely governs the cost of building and maintaining the electricity distribution networks.</p> <p>“If growth in peak demand can be managed or limited, a distribution company may be able to avoid costly infrastructure upgrades, and the subsequent need to pass these costs on to consumers.”<sup>16</sup></p> <p>“The peak demand, rather than the amount of energy consumed, largely dictates network configuration and cost for distributors. This</p>

<sup>14</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 39.

<sup>15</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, pages 20 and 21.

<sup>16</sup> ENA, Charging Matters – Considering new ways to pay for electricity networks, undated, page 4.

	<p>is especially so in the transmission network and the high-voltage part of the distribution networks.”<sup>17</sup></p> <p>“The smoothing of network peaks through hot water load management can avoid, or at least defer, millions of dollars of investment in distribution and transmission networks. Consumers benefit from offering up interruptible load through lower network prices over time.”<sup>18</sup></p>
<ul style="list-style-type: none"> <li>• <b>Role of LRMC for dynamic-efficiency</b></li> </ul>	<p>“Efficient distribution pricing has the benefit of signalling to consumers the long-run cost of capacity upgrades. This is often referred to as long run marginal cost (LRMC) pricing.” [footnote removed]<sup>19</sup></p> <p>“It is generally accepted in economic theory that efficient pricing occurs when prices are based on the long run marginal costs of providing network capacity to consumers. When prices are based on LRMC consumers will adjust consumption (capacity) to a level that benefits them the most in the long run (optimises welfare).”<sup>20</sup></p>

## Potential next steps

Our comments on potential next steps for distribution pricing reform relate to:

- Possible evidence ENA could develop to support individual EDB tariff reform;
- How far ENA should go in developing tariff options that individual EDBs could adopt;
- Work that could be undertaken on determining which version of LRMC to apply (potentially for both distribution and transmission); and
- Transition risks and issues in view of potential TPM changes.

## Ensuring evidence-based decision-making that does not unnecessarily rely on judgement

One of the network pricing principles ENA advocates is that prices be “Actionable” and “provide price signals that consumers can choose to respond to”.<sup>21</sup> We have referred to this previously as pricing that is ‘useful and usable’.<sup>22</sup>

It may be useful, through consumer engagement and other analysis, to test the extent to which consumers could be expected to respond to different types of tariffs and pricing signals.

The discussion paper notes that “Pricing that reflects costs will result in lower prices in the long term”<sup>23</sup> which we agree with as a general statement. However, the paper does not evidence this statement. We consider the Australian ENA distribution pricing review provides useful precedent which could be replicated for New Zealand circumstances. It included analysis which detailed expected overall downward pricing impacts for end-users.

<sup>17</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 11.

<sup>18</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 20.

<sup>19</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 20.

<sup>20</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 20, footnote 17.

<sup>21</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 20, footnote 21.

<sup>22</sup> Transpower, submission to the Electricity Authority, Distribution pricing review, 2 February 2016.

<sup>23</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 6.



Similarly, it may be useful to back up the assertion that “prices that reflect cost are important in the short term because they remove cross-subsidies between consumers, meaning everyone pays a fair price”<sup>24</sup> with quantified evidence of the extent to which cross-subsidies presently exist.<sup>25</sup>

We think that most of these statements are reasonable but, absent evidence to support them, it is hard to judge how important the issues are, or how strong a justification they provide for change (particularly substantive changes). Put another way, what is the size of the problem with distribution pricing the review is trying to address?

The stronger the evidential basis ENA can provide for tariff reform the easier it could be for EDBs to justify their tariff reform proposals and get consumer buy-in (another key element of the ENA pricing principles). We see evidence-based decision-making as much broader than simply proving some form of Cost Benefit Analysis at the tail end of the review.

### The role of ENA versus individual EDBs

While any tariff reforms are a decision for each individual EDB to make, we think that ENA has and could continue to provide an important role in aiding the transition, developing standardised tariff options, communications and planning tools and supporting networks’ actual transitions.

There are clearly substantial synergies for EDBs from use of ENA as a vehicle for dealing with matters of common interest, and to minimise the extent to which individual EDBs have to replicate each other’s processes and work.

### LRMC options

The discussion paper makes clear LRMC would form the basis of the options for peak-usage, capacity-based or time-of-use pricing, but steers clear of an discussion about the different options for defining or determining LRMC. This is reasonable given the consultation is effectively a combined Problem Definition and high-level Options Working Paper.

We think it could be a good idea, if the proposals are to be taken further, for ENA to develop views on how LRMC would be determined (effectively an LRMC working paper, which could build on the Electricity Authority’s on consultation on this matter).

Transpower may have to go through the same exercise, once the Electricity Authority makes a decision on the TPM Guidelines (and potentially in relation to the DGPPs), so we should all consider how best to co-ordinate this work.

Setting over-all optimal distribution and transmission charges requires that the methodologies used are complementary e.g. transmission peak-charges which can readily flow through into the distribution peak-charges. Our starting presumption is that the optimal approach to LRMC is likely to be the same for all EDBs and Transpower – though the form of peak charge may differ e.g. an LRMC-based RCPD charge may be optimal for transmission pricing but may not be suitable for, or liked by, end-users.

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<sup>24</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 6.

<sup>25</sup> There is sometimes looseness around the use of the term cross-subsidy, but ENA capture the definition appropriately: “In order to ensure that one group of consumers is not subsidising another, and that some consumers do not have incentives to bypass the network, prices need to be set at a level such that all consumers face prices that at least cover the incremental costs of supplying them, and no consumer faces prices in excess of the standalone cost of supplying them” [ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, paragraph 17].

## Managing a smooth and non-disruptive transition

The Authority's proposed TPM changes could result in substantial distribution tariff upheaval. It could be a good time to 'kill two birds with one stone' and also implement distribution pricing reform.

This would require careful consideration of how the changes tie in together.

By way of illustration, for example, the prices an EDB might produce, for a distribution pricing methodology based on peak-usage or TOU charges could look very different if:

- The current TPM with RCPD charges is in place (see Vector's pricing),
- A new TPM based on AoB (lump sum) and Residual (capacity) charges is introduced with no peak transmission charge to pass-through into distribution charges, or
- The new TPM also includes a peak-usage charge based on LRMC – potentially moderated peak transmission charges to pass-through.

If the new distribution prices are introduced before changes to the TPM it could result in initially high peak distribution charges, which would then be lowered when the new TPM was put in place.

Please do not hesitate to contact me if you have any queries or would like to discuss the content of this follow-up letter.

Yours sincerely

A handwritten signature in black ink, appearing to be 'JC' followed by a long horizontal line.

Jeremy Cain  
**Regulatory Affairs & Pricing Manager**

## Appendix: Responses to ENA questions

- Question 1** The following features of efficient and effective distribution pricing have been identified: (1) actionable; (2) compliant; (3) cost-reflective; (4) effective in the long term (durable); (5) service-based; (6) simple; (7) stable and predictable.
- (a) Are there any features which you consider should be added, removed or changed in the above list? Please explain your reasons.
- (b) Which of the above features are the most important in determining future distribution pricing?

We support these principles. They are sound for any form of network pricing.

We agree that:

- consumer buy-in is important for durability. As ENA note what might be the theoretically-efficient pricing methodology, may not be the best and consumer buy-in is needed;
- in terms of prices that are “Actionable” we reiterate our view “Network pricing should send pricing signals that are ‘useful and usable’. Clear and simple tariffs that are straight forward for retailers to manage will likely better enable and encourage the transfer of price signals to consumers. Consistent with this, we agree the Authority that “It is not necessary for distributors to set prices that perfectly reflect the cost of the services provided”<sup>26</sup>.
- there can be trade-offs between the principles, including “between pricing that is cost-reflective but is still simple and understandable”, and that “It is important to clearly identify and assess trade-offs of this type”<sup>27</sup> – we have previously commented that “We consider there is a pressing need to simplify distribution pricing ...”;<sup>28</sup>
- consistent with this, ENA has previously noted: “Given that consumers prefer simple flat rate prices, it may be that competitive pressures will reward retailers that retain flat rate pricing structures even if distributors move to introduce more cost-reflective charges”.<sup>29</sup> If consumers prefer simpler tariffs, even if it means they “forgo possible cost savings”,<sup>30</sup> then this may be the most efficient outcome;
- in terms of trade-offs, we also agree cost-reflectivity should not be given “absolute priority ... over stability and certainty”;<sup>31</sup> and
- pricing stability is important if price signals are to be effective: We agree with ENA that “Prices for electricity need to be stable in the long term to provide the right signals to consumers about their investment and consumption decisions”.<sup>32</sup>

In response to some of the other ENA questions we also suggest that consistency with workably competitive market outcomes may also be relevant, particularly in relation to the extent and nature of consumer choice the potential distribution tariff reforms would provide. As Ken Sutherland, Chair of the ENA, notes, part of “Improving the way we price to consumers” is “to ensure that we provide them with choice”.<sup>33</sup>

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<sup>26</sup> Transpower, submission to the Electricity Authority, Distribution pricing review, 2 February 2016.

<sup>27</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 4.

<sup>28</sup> Transpower, submission to the Electricity Authority, Distribution pricing review, 2 February 2016.

<sup>29</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, page 15.

<sup>30</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, page 16.

<sup>31</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, paragraph 46.

<sup>32</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 6.

<sup>33</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page iv.

This may be captured by the “service-based” principle depending on how it is interpreted and applied. Concepts like “service-based” are a bit nebulous and can mean different things to different people (which ENA intimated in its submission to the Electricity Authority, on the evolving technology and distribution pricing consultation, in February). We consider that service-based, customer-focussed and replicating workably competitive outcomes are similar and overlapping concepts.

We note the pricing criteria also contained in the discussion paper goes into more detail about what efficient pricing is. The two sets of criteria overlap, but don’t use the same set of wording. It would be good to clarify the alignment between the two, as well as the Electricity Authority’s distribution pricing principles and decision-making and economic framework.<sup>34</sup>

**Question 2** The ENA has identified five pricing types that it considers in detail in this paper: time of use consumption; customer demand; network demand; booked capacity and installed capacity. Do you agree that these are the five best types of pricing to consider now? Do you agree that other cutting edge pricing options (such as critical peak and real-time pricing) should be left for consideration later?

Please provide your reasons.

We strongly support LRM-based, or LRM-like, charging that provides effective and explicit ex ante signals about the cost and impact of the use of electricity networks (transmission and distribution) during peaks.

We consider the question of what particular form this may take for distribution pricing, including adoption of “cutting edge pricing options”, to largely be a matter between EDBs, retailers and consumers. We do note, though, that the options aren’t necessarily either or e.g. an EDB could offer more than one type of pricing option, providing retailers and consumers greater choice. This may be beneficial if, say, an option like real-time pricing has potential for greater network management benefits but would only suit a minority of consumers/niche retailers.

**Question 3** Do you consider that retail competition can be relied upon to ensure consumers face appropriate distribution price signals?

Please explain why or why not.

With respect, we consider that the discussion paper may be asking the wrong question.

The starting point, as articulated by Ken Sutherland, Chair of the ENA, is that “Any changes must be supported by consumers, and other important stakeholders such as electricity retailers”.<sup>35</sup>

We suggest ENA, and EDBs should be considering what price signals retailers and consumers would consider to be ‘useful and usable’. How do we need to reform distribution tariff options such that retailers will be able to, and be willing to, pass-through the distribution pricing signals?

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<sup>34</sup> The discussion on LRM on the Electricity Authority’s LRM working paper usefully sets out well that LRM pricing is dynamically-efficient, and scores highly on the Authority’s decision-making and economic framework. The Authority, however, seems to have moved away from these positions in its more recent TPM review consultation.

<sup>35</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page iv.

Much of the discussion paper goes directly to the heart of this reconfigured question.

The discussion paper, for example, recognises a general retailer preference for simplicity.

Meeting retailer needs and preferences is also recognised in statements such as:<sup>36</sup>

When designing a new ToU pricing plan, a distributor should consider whether to align to an existing ToU-based pricing offer across neighbouring distribution regions. Retailers are much more likely to pass through ToU-based pricing if they can package together pricing offers from multiple distributors. ToU offers that are aligned across distributors also minimise the transaction and administrative costs for retail marketing and system changes, which encourages retailer participation and subsequent consumer take-up of the new pricing offer.

Electricity retailers are likely to be reluctant to pass-through forms of pricing that consumers would consider unpalatable, or consumers would be unwilling or unable to understand or respond to.

If EDBs set ‘useful and usable’ pricing signals this will create opportunities for retailers to offer tariffs which can save their customers money. Other retailers which do not follow suit may find themselves at a competitive disadvantage. For example, consumers that do not consume high amounts of electricity during peak periods, or are able to shift their load, will tend to gravitate towards retailers that pass-through peak-usage price signals. Retailers that do not pass-through these signals could end up with higher cost/less profitable customers.

ENA has also explained previously that, even with competition, retailers may not pass-through distribution pricing signals if the pricing does not reflect consumer preferences. If, for example, consumers value simplicity over “possible cost savings”:<sup>37</sup>

“Given that consumers prefer simple flat rate prices, it may be that competitive pressures will reward retailers that retain flat rate pricing structures even if distributors move to introduce more cost-reflective charges.

...

“Hence, while we agree that distributors should aim to set more cost-reflective prices, we need to be aware that consumers’ ultimate consumption choices are driven by multiple factors and that consumers typically prefer simple flat rate charges and are often willing to forgo possible cost savings in order to retain a simple and familiar pricing structure.”

If consumers prefer simpler tariffs, even if it means they “forgo possible cost savings”, then this may be the most efficient outcome; consumer welfare may be maximised, even if productive efficiency is not. Ultimately whether, or the extent to which, retailers pass-through distribution pricing signals depends on the extent to which EDBs understand, and respond to, retailer and consumer preferences.

**Question 4** Do consumers see value in load control and ripple control, and is this likely to change in future?

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<sup>36</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 44.

<sup>37</sup> ENA, Submission on Implications of evolving technologies for pricing of distribution services, 2 February 2016, pages 15 and 16.

The preliminary analysis Transpower has undertaken suggests there is substantial benefit from demand-side management, including load control and ripple control, responding to RCPD signals.

The analysis we undertook, for our response to the Electricity Authority's TPM 2<sup>nd</sup> Issues Paper indicates that the combination of Demand Reduction and Distributed Generation, as a proportion of peak demand, in each region is:

- Upper North Island: 9-12%
- Lower North Island: 22-28%
- Upper South Island: 17-30%
- Lower South Island: 15-18%

The significance of this is that the combination of DR and DG equates represents many years' organic demand growth in all four regions.

**Question 5** Do you agree that distributors should engage with end consumers about distribution pricing? Why/ Why not? Please provide your reasons.

Yes.

It is important for EDBs to engage with both retailers and end-consumers.

Electricity retailers, as the direct-customers of EDBs and as the parties that will ultimately determine how distribution prices are passed-through to end-consumers, have an important role to play in any tariff reform or review.

Different retailers will inevitably, and appropriately, have different interests and preferences, depending on their business models. For example, retailers that offer tariffs which expose end-consumers to half-hourly spot market prices may be more open to complex and more dynamic distribution tariff reforms. This reflects that the consumers they target are likely to be more progressive, and open to adapting their electricity usage to respond to pricing signals.

Understanding consumer preferences and how they would respond to potential new pricing signals is important for successful tariff reform, and ensuring evidence-based decision-making. The form of engagement can take any number of forms, such as use of consumer-focus groups, conferences, social media (including EDB facebook pages) etc.

We agree with ENA that "Successful pricing discussions need to focus on the end consumer. Consumer engagement delivers better outcomes for consumers and supports the success of any change".<sup>38</sup> We also agree with the Electricity Authority that "distribution pricing structures around the country will best promote the long-

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<sup>38</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 27.

term benefit of consumers when design is informed by local knowledge. Distributors can achieve this by actively and effectively engaging with the consumers and retailers on their networks when developing distribution pricing structures”.<sup>39</sup>

We note that EDBs are expected to engage directly with consumers on matters such as CPP applications.

**Question 6** Is there additional information that should be included in this paper about stakeholder engagement?  
If so, please explain what should be addressed.

We consider that the current consultation is a valuable contribution to distribution pricing reform. It contains helpful information and analysis.

The next step is planning for a timely and smooth transition to new pricing models.

We encourage a broader role for the ENA to help aid that transition, developing standardised tariff options, communications and planning tools and supporting networks’ actual transitions. It may also be useful for direct involvement from regulators and government: Possibly via a pan-industry steering, will provide stakeholder confidence, help ensure alignment and provide a ‘clearing house’ for difficult or multilateral issues.

It is stated in the discussion paper that “A robust process for developing new pricing structures will involve several iterations of consultation by the ENA and distributors”.<sup>40</sup> We agree but would like to see a clearer road-map of what these iterations will involve and what the next steps are. It could be useful if this included clarification around the expected boundary between the work ENA will do and EDBs will undertake individually. See discussion on “Potential next steps” in the main body of the submission.

**Question 7** How should distributors balance feedback from different stakeholders?

While we trust that our submission is helpful, and want to see distribution and transmission pricing methodologies that work in a complementary and reinforcing manner, the specific commercial arrangements in relation to distribution pricing are ultimately a matter for EDBs and their customers (at both the retail and consumer levels).

**Question 8** Do you prefer two rate or three rate ToU pricing plans (or any other alternative)?  
Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 9** (a) Do you prefer ToU pricing plans that apply peak prices across the entire week (Mon-Sun) or ToU pricing plans that have peaks that apply over weekday (Mon-Fri) only?  
Please provide your reasons.

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<sup>39</sup> Electricity Authority, Implications for evolving technologies for pricing of distribution services – consultation paper, November 2015, page 3.

<sup>40</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 3.

(b) If you prefer peak prices to apply over weekdays (Mon-Fri) only, do you prefer the definition of weekdays for peak prices to include or exclude public holidays?  
Please provide your reasons.

In terms of the operation of the transmission grid, we note that most of the RCPDs occur in the evenings, during the week, and in winter.<sup>41</sup> We recognise there may be a trade-off between trying to target the peaks, and producing tariffs that are simple for consumers to understand and respond to. Whether this balance, means there should or should not be seasonal tariff differentiation, or differentiation between weekdays and weekends, is a matter we consider stakeholders directly affected by these proposals (electricity retailers and consumers) should principally to respond to. It depends on consumer preferences and how they would respond to the different options.

**Question 10** Should peak prices apply throughout the entire year or should they apply only during clearly defined peak months (such as the winter months of May-Sept)?  
Please provide your reasons.

See response to Question 9.

**Question 11** Do you agree with the ToU consumption pricing template?  
Please explain why/why not.

We have not reviewed the template. We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 12** Do you agree with the Customer Demand template?  
Please explain why/why not.

We have not reviewed the template. We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 13** If Network Demand pricing is used, should it be based on fixed or dynamic network peak pricing?  
Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to. We note the type of peak-usage pricing that may be suitable for transmission services, such as RCPD, may not necessarily be suitable or preferred by retailers or consumers.

**Question 14** Are annual or monthly resets for demand pricing more appropriate?  
Please provide your reasons.

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<sup>41</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, Figures 24 – 26.



We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 15** What tools might consumers need access to be aware of Network Demand pricing signals?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 16** Do you agree with the Network Demand template?  
Please explain why/why not?

We have not reviewed the template. We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 17** When consumers are moved to a booked capacity plan for the first time, who should choose their plan?

- The consumer, in all circumstances
- The distributor, in all circumstances
- The distributor, but only if the consumer is unsure of, or does not nominate, their preferred plan

Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to. Consistency with workably competitive market outcomes may be a relevant consideration. Also relevant is the comment from Ken Sutherland, Chair of the ENA, that part of “Improving the way we price to consumers” is “to ensure that we provide them with choice”.<sup>42</sup> Ditto the statement in the discussion paper that “Ultimately, any change in pricing structures will need to be informed by consumer preferences”.<sup>43</sup> In many ways the discussion paper answers its own question.

**Question 18** Distributors could offer several Booked Capacity price plans (or bands) to choose from. What is a reasonable number of plans to choose from?  
Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 19** Assuming it comes at no cost to the consumers, how often should a consumer be allowed to change Booked Capacity plans?

- Never
- Once per year
- Twice per year

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<sup>42</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page iv.

<sup>43</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page vi.

- d. Three times per year
- e. As often as they want

Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to. Consistency with workably competitive market outcomes and the ENA pricing principle of simplicity may be relevant considerations. Also relevant is the comment from Ken Sutherland, Chair of the ENA, that part of “Improving the way we price to consumers” is “to ensure that we provide them with choice”.<sup>44</sup>

**Question 20** Sometimes consumers will choose a Booked Capacity plan that is not most suitable or they have a period of high usage meaning that they go over the capacity of the plan they have chosen. What should happen if the consumer breaches their plan?

- a. Pay a higher rate for the usage above the plan
- b. Receive a rebate if they stay within plan
- c. Automatically moved up to a higher plan

Please provide your reasons.

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to. There is precedent for this type of issue in terms of residential consumer choice of low or high fixed charge tariffs, and the advise retailers are required to provide residential consumers about what tariff would best suit their circumstances.

**Question 21** Do you agree with the Booked Capacity template?  
Please explain why/why not.

We have not reviewed the template. We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 22** Do you agree with the list of pricing assessment criteria presented in Section 9.2?

- a. If not, what criteria should be considered?
- b. What are the most important assessment criteria and why?

Refer to our response to Question 1. We note that the discussion paper contains two overlapping, but distinct, sets of pricing criteria or principles.

**Question 23** Do you agree with the ENA’s high level assessment of each pricing option against the assessment criteria (presented in Section 9.2)? What in your view are the relative benefits, costs, or challenges associated with each pricing option?

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<sup>44</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page iv.

We have not reviewed the assessment in detail. An open question we have is what level of evidence (including, potentially, quantified CBA), does ENA and individual EDBs consider is needed to justify substantive network tariff reform, particularly if there is potential for price shocks?

**Question 24** What do you consider is the optimal combination of pricing components?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 25** Do you foresee any challenges to obtain and supply required data for implementation of preferred price structures? Please provide your reasons.

This is a matter ENA and EDBs should consider as part of the review process. We understand some EDBs consider that they need additional consumer information to make well informed decisions. We have encountered analogous type issues with the level of uncertainty about the extent to which RCPD signals are responded to e.g. by distributed generators and through EDB demand reduction, and the impact removal of these signals would have on parts of the existing transmission grid to meet peak demand, and on future transmission investment requirements.

**Question 26** What is your view on the use of data estimates / profiles for implementation of preferred price structures? How should gaps in information in half hour data be addressed?

We have no comments on this question.

**Question 27** What are the potential changes that could be required by Registry because of moving to service-based price structures?

We have no comments on this question. It is not applicable to Transpower.

**Question 28** What are the potential challenges to Electricity Information Exchange Protocols (EIEPs) because of moving to service-based price structures?

We have no comments on this question. It is not applicable to Transpower.

**Question 29** What are the potential challenges for your data management and billing systems in implementing service-based price structures?

We have no comments on this question. It is not applicable to Transpower.

**Question 30** What other technical implementation challenges do you foresee that can impact on implementation of service-based price structures?

We have no comments on this question. It is not applicable to Transpower.

**Question 31** How can distributors encourage greater uptake of cost reflective types of pricing? Do you prefer mandatory or voluntary adoption approaches, or a combination of both (eg see figures 43 and 44)? What other matters do distributors need to consider under each?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

Ken Sutherland, Chair of the ENA, set out that a “key goal” of “Improving the way we price to consumers” is “to ensure that we provide them with choice, opportunities to take advantage of new technology and ways to save money”.<sup>45</sup> If EDBs succeed in setting prices that offer choice, better opportunities for use of new technology, and the opportunity to save money this should help encourage greater uptake.

It may also be worth considering outcomes in workably competitive markets. Some consumers, for example, may not be able to or want to respond to more sophisticated tariffs and pricing signals. They may be willing to pay a premium for greater certainty about the cost of electricity usage.

The telecommunications sector potentially provides useful precedent – with retail service providers providing a range of pricing choices targeted against different consumer needs e.g. ‘all you can eat’ options for high-use consumers, and pre-pay options which give consumers greater discretion which may suit lower-usage consumers, or consumers with less certain and more variable demand profiles.

An example of the impact of limits on choice or tariff options can be seen with consumers that take-up LPG tank supply for their home, even though there is gas distribution network supply available. It is likely that these consumers prefer to be able to select an, effectively, fully variablised tariff option, rather than relatively high fixed/low variable tariffs on offer through the gas network. A more flexible approach to pricing, in such circumstances, could mean greater uptake of gas reticulation, and (if the tariff enables at least recovery of incremental cost) contribution to the fixed and common costs of the network by a greater number of costs. EDBs and Transpower are somewhat insulated from some of these dynamics because electricity is, at least for the time being, less of a discretionary service than gas or telecommunications.

We think a particular lesson from the telecommunications sector is the importance of choice and ‘one size does not fit all’.

**Question 32** What is a reasonable timeframe over which to shift to cost reflective pricing?

It is not clear how this question could be answered without specific information on the actual proposed new tariffs and how far they depart from existing tariffs, including potential for rate shock. For example, it is noted in the discussion paper that “Moving from a pure consumption-based to a pure capacity-based pricing structure will create the largest price changes of all the cost-reflective pricing structures in this discussion paper”.<sup>46</sup>

While we consider this question to be premature it is one EDBs should keep in mind as they progress their individual tariff reforms (where applicable).

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<sup>45</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page iv.

<sup>46</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 67.

**Question 33** What are your preferred approaches to managing adverse price changes (eg see types of pricing presented in pages 72 to 74) and why? What other approaches should be considered?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 34** What transition issues or challenges do consumers face in the move to cost reflective pricing?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 35** What can distributors do to effectively communicate and engage with consumers during the transition period? What information is most important to provide to consumers during this transition period?

We consider this to be a matter for stakeholders directly affected by these proposals (electricity retailers and consumers) to principally respond to.

**Question 36** What issues or challenges arise for other stakeholders (ie non-consumers) during the transition period? How would you prefer for distributors to communicate and engage with you during the transition period? What information would you like distributors to provide you during this transition period?

An additional transition issue that EDBs may want to consider is how to best manage potentially overlapping distribution and transmission pricing reform. We discuss this in the main body of the submission under “Potential next steps”.

Some of the potential issues are not resolvable at this stage of the respective distribution and transmission pricing methodology reviews, as both the outcome and timing of any changes is not yet known. It would not be known, for example, when a new TPM would be implemented until after Transpower had completed the development of any new or revised TPM Guidelines into a fully developed (and approved) TPM.

Some of the issues worth considering are:

- The impact of two consecutive tariff reforms (one for changes to distribution pricing methodologies, and the other for the TPM) versus managing the changes concurrently;
- The implications of potential TPM changes for the type of LRMC pricing signals ENA is advocating. For example, the optimal distribution peak-usage pricing signal would be higher if RCPD or some form of peak-usage price is retained in the TPM, compared to the Authority’s current proposal to remove transmission peak-usage signals (with LRMC a discretionary component that would only be introduced if both Transpower and the Electricity Authority agreed).

Any such issues would be easier to manage if the distribution and transmission pricing changes work in the same direction, and are consistent.

**Question 37** Are there any matters not covered in this paper that the industry needs to consider in relation to distribution pricing?

Please refer to the main body of our submission; including the section on “Potential next steps”.

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## APPENDIX C: ELECTRICITY AUTHORITY LRMC WORKING PAPER

We consider the Authority's previous LRMC Working Paper assessment of LRMC was orthodox and fundamentally sound. However, the paper overstated the practical problems with applying LRMC relative to beneficiaries-pay options.

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### THE MERITS OF LRMC PRICING

We agree with the Authority's, then, position that LRMC is superior to other pricing options:

- "... charges based on LRMC could promote dynamic efficiency"<sup>1</sup>
- "LRMC is forward looking ..."<sup>2</sup>
- "charges based on the LRMC of transmission would provide efficient price signals about the cost of transmission investment"<sup>3</sup>
- "Peak period prices equal LRMC in workably competitive markets ..."<sup>4</sup>
- "LRMC charges are market-like and are therefore, in principle, more preferred under the Authority's decision-making and economic framework".<sup>5</sup>

These positions are entirely consistent with the views the Authority expressed in the 1<sup>st</sup> Issues Paper and in relation to distribution pricing. For example, the Authority noted that, in areas such as UNI and USI, where "The need for interconnection investment ... is ... largely driven by regional peak demand growth"<sup>6</sup> it is efficient to apply a peak-usage charge, such as RCPD, as long as the level of the RCPD charge doesn't rise substantially, as a result of additional transmission investment, such that "the level of response to RCPD could increase past the efficient level and cause a net economic cost".<sup>7</sup> Capping any peak-usage charge at LRMC, with any revenue shortfall recovered through a residual charge, would achieve this.

We agree beneficiaries-pay options should be seen as 2<sup>nd</sup>-best. As the Authority has noted "Beneficiaries-pay charges do not reflect LRMC. A beneficiaries-pay charge would therefore be less successful than a theoretically efficient LRMC charge at promoting efficient investment"<sup>8</sup>). We also agree that beneficiaries-pay should be considered if LRMC is not practicable ("... the Authority considered that, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency"<sup>9</sup>).

We also agree with the Authority that nodal pricing sends statically efficient (SRMC) pricing signals which fall short of LRMC.

We consider the positions outlined in the LRMC Working Paper are not consistent with the position the Authority has adopted with its beneficiaries-pay (AoB) approach (the principal component of its TPM proposal) and LRMC, even if the LRMC is determined to be practical. The LRMC should not be

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<sup>1</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 4.1.

<sup>2</sup> Ditto paragraph 1.6.

<sup>3</sup> Ditto paragraph 1.4.

<sup>4</sup> Ditto paragraph 1.6.

<sup>5</sup> Ditto paragraph 1.6.

<sup>6</sup> Electricity Authority, Transmission Pricing Methodology: issues and proposal, 10 October 2012, Appendix D, paragraphs 64 and 79.

<sup>7</sup> Ditto paragraph 78.

<sup>8</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 5.20 [emphasis added].

<sup>9</sup> Ditto paragraph 4.3.

subjugated to a discretionary (“additional”) component of the TPM but should be a mandatory component.

## NODAL PRICING

We agreed with the previous position that nodal pricing sends statically efficient (SRMC) pricing signals which fall short of LRM. C.

Despite the fact the LRM. C. Working Paper detailed, uncontroversially, why nodal pricing only sends efficient SRMC pricing signals, and falls well short of sending dynamically-efficient LRM. C. price signals for investment,<sup>10</sup> the 2<sup>nd</sup> Issues Paper ignored this and treated the adequacy of nodal pricing signals “in regard to the timing of future transmission investment”<sup>11</sup> as an open question. The 2<sup>nd</sup> Issues Paper concluded, as a consequence, “in proposing an LRM. C. charge to supplement nodal prices, Transpower would have to demonstrate to the Authority that a price signal over and above the price signal provided by nodal pricing and other transmission charges is necessary to promote efficient investment in, and use of, the interconnected grid”.<sup>12</sup> The Supplementary Consultation, similarly, includes statements that “an LRM. C. charge is most likely to be needed to ration use of the *existing* grid to efficiently defer new investment when, for some reason, nodal prices are not sufficient to do so ...”<sup>13</sup> [emphasis added]. In our view the LRM. C. Working Paper has already addressed these questions, and detailed what the “some reason” is.<sup>14</sup>

## ANALYSIS OF THE LRM. C. WORKING PAPER WITH OUR COMMENT

The table below presents Authority view on aspects of the LRM. C. and our comment to each.

Electricity Authority position	Comment
“... charges based on LRM. C. could promote dynamic efficiency” <sup>15</sup>	Agreed. This reflects an orthodox position on LRM. C. pricing.
“LRM. C. is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand. LRM. C. charges are market-like and are therefore, in principle, more preferred under the Authority’s decision-making and economic framework. Peak period prices equal LRM. C. in workably competitive markets where fixed costs are somewhat large, thus promoting efficient investment. Thus, market-like prices in the TPM would involve setting prices for peak demand periods equal to LRM. C.” <sup>16</sup>	Agreed. Consistent with view in the 2 <sup>nd</sup> Issues Paper that: “The LRM. C. charge is a market-like charge that would restrict use of the interconnected grid when that is efficient. In particular, the Authority considers that an LRM. C. charge could provide an efficient price signal in advance of a major new grid investment programme”. <sup>17</sup>
“Pricing in workably competitive markets produces prices broadly reflective of SRMC and LRM. C.”	Agreed. This reflects an orthodox position on marginal cost pricing.

<sup>10</sup> Electricity Authority, Working Paper, TPM Review: LRM. C. charges, 29 July 2014, paragraph 8.11 onwards. The 2<sup>nd</sup> Issues Paper also addressed this point: refer to Electricity Authority TPM Second issues paper, 17 May 2016, paragraph 124.

<sup>11</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.

<sup>12</sup> Ditto paragraph 125.

<sup>13</sup> Electricity Authority, TPM Second issues paper, Supplementary consultation, 13 December 2016, paragraph 3.151.

<sup>14</sup> And a wide range of submissions, in response to the 2<sup>nd</sup> Issues Paper, addressed this point in terms of “other transmission charges”; specifically, the AoB charges and the Authority’s “shadow pricing” theory.

<sup>15</sup> Electricity Authority, Working Paper, TPM Review: LRM. C. charges, 29 July 2014, paragraph 4.1.

<sup>16</sup> Ditto paragraph 1.6.

<sup>17</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.



Electricity Authority position	Comment
"If grid services were priced as in workably competitive markets, prices would reflect SRMC during off-peak periods and LRMCM during peaks" <sup>18</sup>	
"... nodal prices are likely to under-signal LRMCM so LRMCM charges could potentially promote more efficient investment." <sup>19</sup>	Agreed. The LRMCM Working Paper clearly spelt out the reasons why nodal pricing does not provide (dynamically-efficient) adequate investment pricing signals, yet the 2 <sup>nd</sup> Issues Paper treats this as an open question: "Whether such a [LRMCM] charge would be beneficial depends, in part, on whether nodal spot prices provide an efficient signal in regard to the timing of future transmission investment". <sup>20</sup>
"... the Authority is considering LRMCM charges as they are a market-like charge rather than because an externality has been identified, which would require exacerbators-pay charging to be considered." <sup>21</sup>	LRMCM is consistent with market-like and exacerbator pays. The DM&F makes no reference to exacerbator-pays requiring the existence of externalities.
"In principle, the Authority agrees that an efficient LRMCM charge is likely to be more efficient than a beneficiaries-pay charge." <sup>22</sup>	Agreed. This is consistent with the specification of the DM&E framework. As the Authority has noted:
"The Authority has been considering beneficiaries-pay charges because of their potential to promote more efficient investment. LRMCM charges are potentially a more efficient alternative for achieving this objective." <sup>24</sup>	"Submitters considered that: (a) LRMCM charges were more preferred under the Authority's decision-making and economic framework for the TPM and would better promote the Authority's statutory objective than other options the Authority had favoured such as beneficiaries-pay charges". <sup>23</sup>
"... the Authority considered that, in the absence of a mechanism that produces prices that reflect LRMCM, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency." <sup>25</sup>	
"Beneficiaries-pay pricing would be next preferred if LRMCM charging is impracticable" <sup>26</sup>	
"The [beneficiaries-pay] working paper acknowledged that setting prices according to incremental benefit at best only approximates efficient signals since prices are unlikely to reflect LRMCM." <sup>27</sup>	Agreed. This is inconsistent with the approach Oakley Greenwood applied in the CBA.

<sup>18</sup> Electricity Authority, Working Paper, TPM Review: LRMCM charges, 29 July 2014, page 14.

<sup>19</sup> Ditto, paragraph 8.12.

<sup>20</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.

<sup>21</sup> Electricity Authority, Working Paper TPM Review: LRMCM charges, 29 July 2014, page 11, Table 1.

<sup>22</sup> Ditto Table 1.

<sup>23</sup> Ditto paragraph 1.5(a).

<sup>24</sup> Ditto page 10, Table 1.

<sup>25</sup> Ditto paragraph 4.3.

<sup>26</sup> Ditto page 16.

<sup>27</sup> Electricity Authority, Working Paper, TPM Review: LRMCM charges, 29 July 2014 paragraph 4.3.

Electricity Authority position	Comment
<p>“Beneficiaries-pay charges do not reflect LRM. A beneficiaries-pay charge would therefore be less successful than a theoretically efficient LRM charge at promoting efficient investment.”<sup>28</sup></p>	
<p>“LRM charges ... have been applied in the United Kingdom (UK) except Northern Ireland ... However, unlike New Zealand, the UK does not have nodal pricing in their wholesale electricity markets (which provides price signals that reflect at least the short-run marginal cost (SRM) of transmission). Nevertheless, the UK experience is relevant as the rationale for their LRM charges is promotion of efficient investment.”<sup>29</sup></p>	<p>Agreed. The impact of nodal pricing (reflecting SRM) can be taken into account when setting LRM charges, as reflected in the Authority’s proposed Guidelines.</p>
<p>“Submitters considered that ... Practical methods of applying LRM charges had been identified earlier in the review, such as the tilted postage stamp, and LRM charges could also be readily applied by other means such as modifications to the status quo and the Authority’s zonal SPD charge proposal. The Commerce Commission’s application of total service long-run incremental cost (TSLRIC) charges to telecommunications may provide insights to the application of LRM charges”.<sup>30</sup></p>	<p>Agreed. There are a range of methods that could be adopted. The four region LRM pricing methodology Oakley Greenwood modelled is probably one of the simpler LRM options that could be adopted/which would result in the smallest changes from the status quo.</p>
<p>Practical issues with LRM</p>	
<p>“The beneficiaries-pay working paper ... suggested that the 'loop flow' characteristics of the interconnected grid, combined with the large number of parties using the grid, made it impracticable to apply LRM charges. The Authority therefore considered that a beneficiaries-pay approach is the next best option in terms of efficiency and practicality”.<sup>31</sup></p>	<p>The Authority noted “Submitters considered that ... The reasons that the Authority had advanced for not investigating LRM charges further were not valid as the SPD charge indicated practical difficulties such as dealing with loop flows and large number of grid users under LRM could be readily overcome”.<sup>32</sup></p> <p>The Authority, itself, recognised “Methods are available that mean loop flows do not prevent calculation of LRM charges”.<sup>33</sup></p>
<p>“There are a number of practicability issues that would need to be addressed before applying an LRM charge. On a technical level these include:</p> <p>(a) the definition of LRM to be used</p> <p>(b) the methodology used for calculating LRM – MIC, AIC, LRIC or another methodology</p>	<p>These “practicability issues” are straightforward to overcome relative to the challenges with applying the AoB methodology. As the Authority has noted, LRM has been implemented in other jurisdictions. Matters such as “forecasting demand” is a standard part of price</p>

<sup>28</sup> Ditto paragraph 5.20.

<sup>29</sup> Ditto 7.10.

<sup>30</sup> Ditto, paragraph 1.5(c).

<sup>31</sup> Ditto paragraph 1.4.

<sup>32</sup> Ditto paragraph 1.5(b).

<sup>33</sup> Ditto 29 July 2014 page 29.

Electricity Authority position	Comment
(c) the appropriate approach for forecasting demand for transmission services to be used for calculating LRMC ... <sup>34</sup>	determination under Part 4 Commerce Act.
<p>“LRMC charges provide price signals based on investments that are expected to occur in the (distant) future. The LRMC charges for each investment reduce to zero when the new asset is commissioned. Once a party is charged for future investments they would appear to have perverse incentives to push for those investments to occur as soon as possible so as to reduce their charges to a minimum”.<sup>35</sup></p>	<p>This comment assumes a particular form of LRMC, which is applied on a granular investment by investment basis.</p> <p>The concern the Authority raises is straightforward to address.</p> <p>It is dealt with under both Transpower’s Simplified Staged Alternative, and the Authority’s proposed AoB TPM, by allocating new investment using a form of AoB.</p>
<p>“An LRMC charging regime may be unsustainable as parties would be paying for assets/services that don’t yet exist ...”<sup>36</sup></p>	<p>This statement is slightly misleading. The Commerce Commission sets the amount parties pay (overall) is based on the current and forecast costs of providing transmission services over the 5-year regulatory period.</p>
<p>“There is also the issue of whether the regulator can reasonably assess the accuracy of the forecasts of demand and transmission investments. Those forecasts are likely to change over time, and new investment and technology options will arise over time. These issues lead the Authority to question whether the charging regime will be sufficiently robust over time to be sustainable.”<sup>37</sup></p>	<p>These are issues the Commerce Commission needs to address when it sets its price determinations under Part 4 Commerce Act. As the Authority noted “Regarding forecasting demand, the demand forecasts used to determine Transpower’s individual price-quality path (IPP) under Part 4 of the Commerce Act could be used”.<sup>38</sup></p> <p>The types of assessments required for LRMC pricing would be straightforward relative to the requirements for applying the Authority’s proposed AoB methodology.</p>
<p>“More fundamentally, an LRMC charging regime may be unsustainable as parties would be paying charges based on assets/services that don’t yet exist. The charges are likely to be viewed by payers as critically dependent on questionable assumptions and forecasts, and ongoing revisions to those assumptions and forecasts would likely make it clear that the setting of the charge is highly subjective. These issues lead the Authority to question whether the charging regime would be sufficiently robust over time to be sustainable.”<sup>39</sup></p>	<p>These issues would be far more severe under AoB.</p> <p>If issues about the charges being based on “questionable assumptions and forecasts”, and that “setting of the charge is highly subjective” is sufficient grounds to reject LRMC, then the</p>

<sup>34</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014 paragraph 1.4.

<sup>35</sup> Ditto paragraph 1.18(a).

<sup>36</sup> Ditto paragraph 1.18(b).

<sup>37</sup> Ditto paragraph 1.18(b).

<sup>38</sup> Ditto paragraph 8.3.

<sup>39</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014 paragraph 8.37.

Electricity Authority position	Comment
<p>“The Authority notes that these practicability issues are considerable and, to the extent they can be resolved, significant time would be required.”<sup>40</sup></p>	<p>Authority’s AoB charge proposals would also need to be rejected.</p>
<p>“if [sic] LRMC charges were applied but did not fully recover Transpower’s, costs the Authority’s decision-making and economic framework implies a beneficiaries-pay charge should be applied to recover remaining costs. The combination of LRMC and beneficiaries-pay charges, and possibly residual charges, would be more complex than the status quo.”<sup>41</sup></p>	<p>The combination of beneficiaries-pay and residual charges under the Authority’s proposals would also be more complex than the status quo.</p>
<p>“A quantified CBA would be required to determine whether LRMC charges would provide net benefits relative to the status quo. The Authority’s preliminary assessment is that LRMC charges could provide net benefits relative to the status quo. A final assessment would depend on whether the potential efficiency improvements resulting from LRMC charges would occur in practice under a regulated regime, and if so, whether they would outweigh the significant implementation, operational and other costs of applying those charges.”<sup>42</sup></p>	<p>The Oakley Greenwood CBA determined that a simplified 4-region LRMC methodology would provide (modest) net benefits relative to the status quo.</p> <p>The “implementation, operational and other costs of applying [LRMC] charges” would be smaller than that for the 2<sup>nd</sup> Options Paper AoB charges.</p>
<p>“LRMC charging involves estimates of LRMC based on current technology but relates to future investment costs. This means there would be a risk that if the investment is actually made: (a) the technology used for that investment may be different from that on which the LRMC calculation is based ...</p> <p>“The main risk with (a) would be that technological change raises a risk of a mismatch between LRMC charges and the actual costs of the investment. Since technological change would probably be more likely to reduce rather than increase costs, LRMC charges may be higher than would be efficient. The consequence of an excessive LRMC charge would be lower demand for transmission services than is efficient and inefficient deferment of investments.</p> <p>“While this risk is a real one, the key question is whether the efficiency consequences of this are worse than the alternatives. For example, the charges under the status quo and beneficiaries-pay charges are based on the actual costs of investments that have been incurred, ie historical costs. This means that to the extent there is a risk of over-charging with LRMC charges it may actually be worse for the status quo and beneficiaries-pay.”<sup>43</sup></p>	<p>The peak-usage signal would be zero if an LRMC charge is not adopted.</p> <p>An imperfect peak-usage signal will be more accurate and more efficient than a zero peak-usage signal.</p> <p>With respect, we consider that the commentary that AoB charges are based on historic costs and therefore more accurate than LRMC compares apples and oranges and is spurious.</p> <p>The estimation of LRMC, based on future investment-costs, will be more straightforward, and less prone to error, than estimating the private benefits consumers will receive over the lifetime of AoB assets.</p>

<sup>40</sup> Ditto paragraph 1.19.

<sup>41</sup> Ditto paragraph 1.20.

<sup>42</sup> Ditto paragraph 1.23.

<sup>43</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraphs 8.32-8.34.



29 May 2018

Commerce Commission  
Wellington 6140

By email: [regulation.branch@comcom.govt.nz](mailto:regulation.branch@comcom.govt.nz)

## Auckland International Airport's pricing decisions

We welcome the opportunity to submit on the Commerce Commission's draft report "Review of Auckland International Airport's pricing decisions and expected performance (July 2017 – June 2022)" published 26 April 2018.

Our comments are limited to Chapter 4 and the prices set by Auckland Airport. We have previously commented on application of different WACC percentiles to airports, and for information disclosure, and don't repeat those comments here.<sup>1</sup>

### Consistency of approach to network utility pricing

We have a particular interest in airport pricing because of the strong parallels, and lessons that can be learnt, across the different network utility sectors, including airports, electricity (both distribution and transmission), gas, roads, telecommunications and water. We would like to see a coherent and consistent approach, regardless of the sector and who the regulator is (if any).

Differences in pricing approaches across each of the sectors should reflect industry-specific, and/or individual operator-specific, circumstances.

### Towards a generic set of pricing principles applicable across all sectors

We consider the principles the Commission has used to assess Auckland Airport's pricing methodology are fundamentally sound.<sup>2</sup> We note there are any number of variants to the Commission's pricing principles that are equally valid.<sup>3</sup>

None of the Commission's pricing principles are industry-specific. We would be equally comfortable if the principles were applied universally, including in relation to electricity and electricity transmission.

However, there are nuances we would add for clarity - prices should be actionable, simple (no more complex than necessary), and understood:

- For "the price to ensure a good or service is consumed by those that value it the most" (principle 3) and that prices "enable consumers to make price-quality trade-offs" (principle 4), the prices should be actionable i.e. consumers need to understand and be able to respond to the price signal(s).

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<sup>1</sup> Transpower, Airport WACC percentile review consultation, 16 March 2016.

<sup>2</sup> Commerce Commission, Review of Auckland International Airport's pricing decisions and expected performance (July 2017 – June 2022), 26 April 2018, paragraph 275.

<sup>3</sup> For example, ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 3.

- Simplicity is an important building block to allow for “development of prices [to be] transparent, and promote price stability and certainty for consumers” (principle 5).

## The importance of peak-usage or capacity pricing

The consultation paper usefully illustrates there are a number of different reasons why peak-usage pricing can be a good idea, but whether it ultimately should be adopted can depend on industry or firm specific factors. Drawing on the consultation paper, we would summarise the reasons for considering the use of peak-usage pricing as:

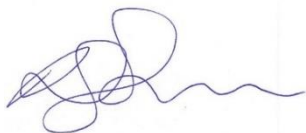
- Helping to ensure prices are subsidy-free (principle 1) – relevant where investment is driven by peak-demand. (The consultation paper is silent on this element but we consider it relevant).
- A way to delay or avoid the need for future investment in capacity expansion (principle 2) – this is relevant where peak-demand is price responsive.
- An efficient (non-distortionary) way to recover fixed and common costs (principle 2) – this is relevant where peak-demand is price responsive.
- As a corollary to the last point, to (efficiently) encourage greater off-peak demand (principle 2) – relevant where off-peak demand is price responsive.

The last three points are reflected, succinctly, in the consultation paper with the observation “Although there has been significant demand growth since PSE2, submissions from airlines suggest there may be little demand response to congestion charging. However, we note this lack of demand response may indicate there is room to increase charges at peak times while lowering charges to off-peak users who may be more responsive, and thereby increase overall demand. This is an area which would benefit from greater consideration”.<sup>4</sup>

We have emphasised the importance of our own peak-usage charges for curbing peak-demand and delaying the need for future transmission investment (we note this reason may not be as relevant to Auckland Airport’s circumstances or future investment (runway) needs). The role for peak-usage charging is likely to grow over-time with the emergence of new technologies. For example, if electricity network pricing (transmission plus distribution) does not send the correct signals then consumers could charge their electric vehicles at the same time, increasing or exacerbating existing peaks. As the uptake of electric vehicles increases the issue will become larger.

Finally, and as reflected in our strategic papers *Transmission Tomorrow* (2016) and *Te Mauri Hiko – Energy Futures* (2018), technological developments are changing consumer demand, and disrupting the link between population (GDP) and electricity demand. We see a much greater future risk that if investment is made earlier than necessary it could become obsolete. The potential for obsolescence is a much bigger concern than the simple loss of the time value of money from investing too early (but in something that will ultimately be needed).

Yours sincerely



Rebecca Osborne  
**Regulatory Affairs and Pricing Manager**

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<sup>4</sup> Commerce Commission, Review of Auckland International Airport’s pricing decisions and expected performance (July 2017 – June 2022), 26 April 2018, paragraph 272.



# The role of peak pricing for transmission

2 November 2018

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## Purpose

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The Electricity Authority (Authority) wrote a letter on 12 July 2018 (Attachment A) offering “Transpower the opportunity to provide evidence as to whether or not the removal of the Regional Coincident Peak Demand (RCPD) charge [from the Transmission Pricing Methodology (TPM)] would have an adverse effect on the ability to meet peak demand.” We agree that any reform of the TPM should be evidence based.

This report provides our response to the Authority’s letter and presents our supporting evidence. We focus on the role of peak pricing in the TPM more generally than just RCPD, and consistent with our position throughout the Authority’s transmission pricing review.<sup>1</sup>

## The evidence supports our views on the importance of peak pricing

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The evidence presented by this report demonstrates that peak pricing for transmission saves consumers money by deferring new investment, and that electricity users do and will respond to peak prices signals.

The analysis reinforces our views on the risks and potential effects, or value, of peak pricing in the TPM. Most recently we summarised our views in our submission responding to the Authority’s December 2016 proposal as follows:<sup>2</sup>

**“A peak price signal is essential for an efficient TPM.** We disagree with the Authority’s reasoning and position on a peak ... charge. The Authority’s current path risks grid over-build and security problems which could swamp any benefits from TPM change.”<sup>3</sup>

“Transpower remains firmly of the view [that a] peak price signal is essential to avoid grid overbuild. Having considered the reasoning in the Supplementary consultation we:

- believe the Authority’s position on [peak] price signals ... will unnecessarily impose costs on Transpower and consumers through higher than optimal:
  - transmission costs: whether through incremental investment to meet higher GXP level peak demand or the cost of procuring non-transmission solutions
  - energy costs: through increased reliance on peaking generation and the additional costs this imposes on consumers
  - security of supply risks: for the reasons set out in Appendix C [of our submission], we consider Concept Consulting’s assessment of the security of supply risks optimistic.
- consider the Authority places undue reliance on a ‘shadow’ price signal provided by the [Area of Benefit] charge and do not understand its apparent opposition to [any peak] charge.”<sup>4</sup>

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<sup>1</sup> <https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/>

<sup>2</sup> The Authority’s [Dec16 proposal](#) provided for peak pricing as a possible “additional component” in the form of an LRM charge. The draft TPM Guidelines stated: “Transpower may only include an LRM charge in the TPM if a price signal over and above the price signal provided by nodal pricing (or that could be provided by nodal pricing with direct refinements to the spot electricity market), other transmission charges, and any grid support arrangements relied on by Transpower to efficiently defer transmission investment is necessary to promote efficient investment in, and use of, the interconnected grid.”

<sup>3</sup> Transpower [submission](#) to Authority’s Supplementary Consultation 24 February 2017, Page 3

<sup>4</sup> Transpower [submission](#) to Authority’s Supplementary Consultation 24 February 2017, Page 5

Our proposal to undertake a second operational review of the TPM in 2017 suggested testing different forms of peak pricing that might be achieved through incremental reform of the TPM.

We agree with the Authority there is potential benefit in reform of the current peak pricing methodology. However, our analysis strongly reinforces our belief that the risks of removing peak pricing from the TPM far outweigh any potential benefits. Or, expressed another way, the economic risk from over-signalling the value of peak use of the grid (too high a peak price) are much less than the economic and security risks from under-signalling (too low or no peak price).

## Evidence we have pulled together – a summary

The information and evidence we have been able to collate in the time available, on the benefits of peak pricing in the TPM, consists of three reports attached to this report. A high-level summary of each follows.

<p><b>Frontier Economics</b></p> <p>Peak charging: A review of price elasticity of electricity demand</p> <p>16 October 2018.</p> <p>(Attachment B)</p>	<p><b>Peak pricing flattens load profiles</b></p> <ul style="list-style-type: none"> <li>• High peak-use tariffs tend to reduce peak-time demand, and residential consumers are more responsive to peak prices than non-residential.</li> <li>• Consumer response to peak-use tariffs are more pronounced in the long-term than in the short term.</li> <li>• Demand response effects are much greater where automated or semi-automated response-enabling technologies have been applied. It is reasonable to infer technological change will result in demand for electricity being more flexible, and more responsive to price signals.</li> <li>• In some cases, high peak-time tariffs also reduce off-peak demand due to a ‘conservation’ effect, but where this occurs the overall effect is a flattening of load.</li> </ul>
<p><b>Transpower, as the Grid Owner</b></p> <p>Impact of removal of RCPD (peak pricing) on transmission investment</p> <p>October 2018.</p> <p>(Attachment C)</p>	<p><b>Removal of peak charges would bring forward transmission investments</b></p> <ul style="list-style-type: none"> <li>• We looked at the potential impact on increased peak loads, using North and South Island case studies.</li> <li>• A 3% increase in peak load would bring the investments forward by 2 years (an increase in investment cost of approximately 8%). A 7% increase would bring the investment forward 4 to 6 years (up to 16% higher investment costs).</li> <li>• This is particularly notable given (i) the assumptions we used were deliberately conservative, and (ii) Transpower is at the tail-end of a large investment programme so capacity constraints are less pronounced.</li> </ul>
<p><b>Transpower, as the System Operator</b></p> <p>Impact of removal of RCPD (peak pricing) on the electricity system and market</p>	<p><b>Peak pricing has positive system impacts</b></p> <ul style="list-style-type: none"> <li>• Our network peak price is an additional pricing signal to any spot market (nodal) prices including to parties, such as EDBs, that are not necessarily exposed to energy pricing.</li> <li>• Spot prices can be very sensitive to small changes in demand from changes in load control. A network peak price signal can result in lower wholesale prices and reduces the need for more expensive non-renewable generation (lowering emissions).</li> </ul>

October 2018. (Attachment D)	<ul style="list-style-type: none"> <li>To the extent load control by EDBs curbs spot prices, the action avoids the need for consumers to reduce demand in response to otherwise-higher spot prices.</li> </ul>
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We have previously provided the Authority our feedback on the 2016 analysis by Concept Consulting referred to in your letter.<sup>5</sup> We do not repeat our feedback here but confirm we consider “Concept Consulting’s assessment of the security of supply risks optimistic” and it would not be prudent to rely on that analysis.

## What are the reasons for applying peak pricing?

Network utility investment is lumpy by nature, which forces network utilities to invest more than is needed earlier. The economies of scale are such that an optimal new network investment will be oversized initially. Consequently, even if demand has only small responses to increases in prices substantial delay to and savings in network investment are realised by promoting downward pressure on peak demand.

The Authority has described the benefit of peak pricing well in the context of distribution networks and these comments apply equally for transmission networks. We agree with the Authority that network pricing structures should “signal to network users the cost of new capacity” and “encourage consumers to take actions that reduce current or future network costs ...”.<sup>6</sup>

The TPM is a cost allocation methodology and so the corollary to higher on-peak prices is lower off-peak pricing. Demand can be flattened by reducing peak demand and increasing off-peak demand. The stronger the cross-price elasticity of demand between peak and off-peak, and the more elastic off-peak demand is, the greater this (efficiency) benefit will be.

The Frontier Economics report into price elasticity studies showed that, in some cases, high peak-time tariffs also reduce off-peak demand due to an overall ‘conservation’ effect. However, where this occurs, consumers typically still increase the ratio of their off-peak to peak consumption. The overall affect is a flattening of load profile.<sup>7</sup>

The Commerce Commission made similar comments about the benefits of peak pricing in relation to Auckland International Airport: “... lack of demand response may indicate there is room to increase charges at peak times while lowering charges to off-peak users who may be more responsive, and thereby increase overall demand. This is an area which would benefit from greater consideration”.<sup>8</sup>

<sup>5</sup> Transpower [submission](#) to Authority’s Supplementary Consultation 24 February 2017, Appendix C.

<sup>6</sup> Electricity Authority, [Consultation Paper](#), Implications of evolving technologies for pricing of distribution services, 3 November 2015, page G.

<sup>7</sup> Frontier Economics, Peak-usage charging: A review of price elasticity of electricity demand, 16 October 2018 (Attachment 2).

<sup>8</sup> Commerce Commission, [Review of Auckland International Airport’s pricing decisions and expected performance](#) (July 2017 – June 2022), 26 April 2018, paragraph 272.

## Peak pricing is a vital component of the TPM now and for the future

The TPM is more than a revenue recovery mechanism for Transpower. We consider it plays a vital role in optimising the need for future investment in the transmission grid. Peak pricing – be it the current RCPD method or some alternative – is a conventional and orthodox element of network utility pricing commonly used internationally to provide downward pressure on demand for future transmission investment.

The analysis presented in Attachment C demonstrates that absent peak pricing, Transpower would need to invest more, earlier, with the consequence that our transmission charges would be higher.

As reflected in our strategic papers *Transmission Tomorrow* (2016) and *Te Mauri Hiko – Energy Futures* (2018), technological developments are changing consumer demand, and disrupting the link between population (GDP growth) and electricity demand. While the extent and timing of change is uncertain, there is wide acceptance the traditional utility supply to consumers (one directional flow) will change in shape and direction in coming decades. Consumers will invest in self-supply and self-management systems (including behind-the-meter solar generation and battery storage<sup>9</sup>), and to transition their other energy demands to electricity (including electric vehicles).

Peak pricing for transmission helps to preserve our option value into an increasingly uncertain future by providing downward pressure on peak demand growth. While there has been much discussion about the regulatory implications of emerging technology and business models, there has been less about the potential implications for investments in long-lived central infrastructure including transmission. As consumers' demand for transmission services evolves we see a much greater risk of investing in assets that are required only for a decade or two (maybe less) of their perhaps four, five, or more decade physical lives.<sup>10</sup> The faster peak demand grows in the short or medium term, the higher the risk we invest in new assets that become obsolete but must still be paid for.

## Peak pricing supports a just, affordable transition to a low-emissions future

We anticipate demand for grid-supplied electricity will grow for some time yet, as New Zealand relies heavily on electrification to accelerate our response to climate change, and then may taper off following widespread consumer uptake of new technologies. In our view consumers will invest, and increasingly as the price of new technologies falls, for reasons other than just price or economics.

Peak pricing is a critical component of optimising the utilisation or capacity factor of transmission assets (flattening demand and enabling more energy to be supplied through the same assets), and so lowering per-unit transmission charges payable over-time. A TPM without peak pricing will materially heighten the

<sup>9</sup> We note the views [expressed by the Authority's \(then\) Chief Executive in June 2018](#) that the current TPM approach will encourage businesses to buy batteries for the purpose of shifting transmission charges to other customers. We disagree that any such incentive will be significant. Our discussion document [Battery Storage in New Zealand](#) found that batteries offer greater value where there is the potential to provide a range of services both for the owner directly, and upstream to the whole network. Managing TPM charges over a few half-hours per year will not make the business case for a battery investment.

<sup>10</sup> We have, for example, some assets that are more than 80 years old and still fit for purpose.

prospect we invest in new transmission capacity earlier than we have to and in assets that become obsolete following mass uptake of new technologies.

We consider an affordable and just transition to a low-emissions economy is promoted by retention of peak pricing in the TPM (whether in its current form or a different form).

## **Distribution pricing and transmission pricing should be complementary**

Distribution and transmission pricing should operate in a joined up and complementary manner.<sup>11</sup> The justification the Electricity Price Review<sup>12</sup>, Authority,<sup>13</sup> Electricity Networks Association (ENA)<sup>14</sup> and others<sup>15</sup> have provided for peak charges, and its variations, are equally valid for transmission.

We consider an end-consumer making decisions about whether to consume peak or off-peak should face price signals which reflect the cost of both the distribution and transmission networks. This is reinforced by ENA data which “suggests a strong correlation between transmission and distribution network peak demand periods”.<sup>16</sup> The alignment of our peaks with distributor peak was illustrated by the ENA using Transpower data.<sup>17</sup> ENA concluded this lends itself to reflecting transmission peak pricing (the current RCPD) into standard time-of-use pricing for distribution and end-consumer pricing. We agree with ENA’s views.<sup>18</sup>

The types of tariff reform being considered for distribution would complement and support the current or a different approach to peak pricing in the TPM.

## **Nodal energy pricing is not a substitute for network peak pricing**

The difference between short-run, efficient, nodal pricing and dynamically efficient network pricing is well canvassed in economic literature and in the ongoing debate over transmission pricing in New Zealand. The Authority’s LRMC Working Paper detailed how nodal pricing only sends efficient short run marginal cost (SRMC) energy pricing signals, and falls short of dynamically-efficient price signals for network investment. We agree with the Authority’s explanation of why nodal energy pricing sends (statically) efficient short-run price signals, which provide generation investment incentives, but does not substitute for network peak pricing for optimising network investment.<sup>19</sup>

<sup>11</sup> Refer, for example, to our submission [to the ENA](#) on distribution pricing (Distribution Pricing: New Pricing Options for Electricity Distributors, 23 December 2016) and, more recently, [to the Commerce Commission](#) on airport pricing (Auckland International Airport’s pricing decisions, 29 May 2018).

<sup>12</sup> Electricity Price Review, HIKOHIKO TE UIRA [FIRST REPORT FOR DISCUSSION](#), 30 August 2018, sections 4 and 5.

<sup>13</sup> For example, Authority [consultation paper](#), Implications of evolving technologies for pricing of distribution services 3 November 2015.

<sup>14</sup> For example, ENA, [New Pricing Options for Electricity Distributors](#), November 2016

<sup>15</sup> For example, ACCC report [Restoring electricity affordability & Australia’s competitive advantage](#), 11 July 2018

<sup>16</sup> ENA, [New Pricing Options for Electricity Distributors](#), November 2016.

<sup>17</sup> ENA, [New Pricing Options for Electricity Distributors](#), November 2016.

<sup>18</sup> ENA, [New Pricing Options for Electricity Distributors](#), November 2016.

<sup>19</sup> Electricity Authority, [Working Paper](#), Transmission Pricing Methodology Review: LRMC charges, 29 July 2014

Nodal prices reflect well the effect of transmission on energy costs resulting from losses and constraints, but not the capital cost of transmission investment: nodal prices would be the same whether relieving a constraint would cost \$1 or \$1-billion.

## Concluding remarks

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Like any form of administered pricing the current transmission pricing methodology isn't perfect. Where there are problems with the TPM we want to work with the Authority and industry to fix them. We have been clear in submissions that the current peak price for transmission (RCPD) may sometimes be overly strong. In our view durable reform of the TPM will require comparison of the long-term benefits to consumers of RCPD against modified forms of RCPD, alternative forms of peak pricing, and no peak pricing.

While there is little major load-growth-driven transmission investment on the immediate horizon, this will not last long into a future of decarbonisation and electrification. To be robust, the TPM need to be future-focused and future-proofed, which in our view requires peak pricing.

The focus of the TPM is longer-term (dynamic efficiency) on future investment and capacity requirements. We can meet peak demand growth by simply building more and bigger assets, but this would mean higher priced, less affordable electricity supply for consumers, and in our view wouldn't be efficient.

We agree with the Authority's views on distribution pricing, that what is important is the impact absence of peak prices could have on peak demand and the need to bring forward investment in network capacity.

We consider the impacts and risks of removal of peak pricing on long-term investment and price levels should be an important focus of the Authority's transmission pricing review. This is consistent with the Authority's position that longer-term dynamic efficiency is more important than short-term efficiency.

**Attachment A**

**Electricity Authority letter to Transpower, 12 July 2018**

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12 July 2018

By Email

Alison Andrews  
Chief Executive  
Transpower

Dear Alison

**TPM: effects of removing the Regional Coincident Peak Demand (RCPD) charge**

I am writing to offer Transpower the opportunity to provide evidence as to whether or not the removal of the Regional Coincident Peak Demand (RCPD) charge would have an adverse effect on the ability to meet peak demand.

As you are aware, on 26 June 2018 the Authority announced the 'next steps' we are taking in our review of the transmission pricing methodology (TPM) guidelines. We outlined the main new transmission charges that we intend to comprise the pricing methodology under proposed revised TPM guidelines. The new charges, including a benefit-based charge and a residual charge, would be expected to replace the RCPD charge and the HVDC charge. Also, we are contemplating including an option for having a charge for controlling peak demand if and where analysis shows there would be a long-term benefit to consumers from using it in addition to nodal pricing and the other components of transmission charges.

One of the key elements of the required analysis relates to the question of the likely effects of removing the RCPD charge on the ability to meet peak demand.

I note that Transpower and others have made submissions to the Authority on the potential risks arising from the removal of the RCPD charge. Also, the Authority has commissioned analysis from Concept Consulting on this issue. Some brief discussion of this previous analysis is set out in the appendix to this letter.

The Authority has not yet formed a definite view on the likely effects of removing the RCPD charge on the ability to meet peak demand. As we noted in our TPM Supplementary consultation paper, while the proposal appeared unlikely to reduce the Winter Capacity Margin below efficient levels, there may, however, be more localised areas of system pressure.

In order to assist the Authority's analysis on whether there is a long-term benefit to consumers from an additional demand control charge, we invite Transpower to provide its evidence identifying any location where removal of the RCPD charge would have an adverse effect on the ability to meet peak demand. At the same time, Transpower may also wish to provide any evidence that a charge to control peak demand (such as potentially an LRMC charge) would be economically justified if the RCPD charge were removed (such as, whether an LRMC charge might provide efficient incentives to consumers making long-term investment decisions).

In doing so, you may wish to take account of the views that the Authority expressed in the Second issues paper that in most circumstances nodal prices should be sufficient to constrain grid use to capacity.



To allow time for the Board to consider this information, the analysis would need to be submitted to the Authority by 31 October 2018.

My team would be happy to discuss this matter further if required. Please direct any queries to John Rampton or Tim Sparks.

On a related matter, I'd also like to take this opportunity to thank you for the attendance of Alex Ball and Rebecca Osborne at the Authority Board meeting on 28 June to discuss the joint report on benefit-based approaches to transmission pricing in the United States . The report and resulting discussion were much appreciated by our Board.

Yours sincerely

A handwritten signature in blue ink, appearing to read 'ADT', with a stylized flourish at the end.

Androula Dometakis  
**Acting Chief Executive**

## **Appendix: Previous analysis on the effects of removing the RCPD charge**

Transpower and others have made submissions on the potential risks arising from the removal of the RCPD charge. For example, in its submission of 26 July 2016 in response to the Authority's Second Issues paper, Transpower submitted that:

“Removing [the RCPD signal] risks triggering a surge in peak demand, potentially resulting in inefficient investment. We see it as essential that a credible peak price signal is developed before RCPD is removed. We consider this should be an LRMC or LRMC-like charge, designed to operate in conjunction with other peak management techniques (demand response, future ACOT arrangements etc).”

In support of this submission, Transpower provided to the Authority:

- the results of a high-level analysis of potential implications of removing the RCPD peak price signal, conducted by Transpower staff (power systems planning and system operations); and
- the results of modelling of 'gross system demand' (adding estimated demand response and distributed generation to net GXP level demand) carried out by Scientia Consulting.

Transpower found, on the basis of the above analysis, that:

- 20% of 'gross demand' is met by demand response [DR] and distributed generation [DG]
- the grid cannot meet gross demand in all areas. Extreme change in DR and DG behaviour will affect grid operations, create market constraints with increased opportunities for pivotal behaviour by generators. It may lead to load shedding.

Subsequently, the Authority commissioned analysis from Concept Consulting on this issue (which was shared with Transpower for comment). In its report (Winter Capacity Margin – potential effect of recent transmission pricing and DG proposals, November 2016), Concept found that while the Authority's TPM proposals (and separate proposals with respect to DG) could have some impact on the ability to meet peak electricity demand, these changes were unlikely to reduce the Winter Capacity Margin (WCM) below efficient levels. Concept's report was published for consultation with the Authority's TPM Supplementary consultation paper.

The Concept analysis was an island-based assessment and regional effects were out of scope. As Transpower noted in its submission in response to the Authority's TPM Supplementary consultation paper, there may be some within-island effects that are not captured by an island-based assessment, which would be worth exploring. Transpower also noted its views on other aspects of the Concept analysis, as did other submitters.

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**Attachment B**

**Peak Charging: A review of price elasticity of electricity demand  
Frontier Economics, 16 October 2018**

# PEAK-USE CHARGING

A REVIEW OF PRICE ELASTICITY OF ELECTRICITY DEMAND

16 OCTOBER 2018



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# EXECUTIVE SUMMARY

Demand elasticity refers to the responsiveness of demand to changes in price. Time-based tariffs can be classified broadly as time-of-use (TOU) rates, real-time pricing and critical peak pricing (CPP). These rates expose customers to varying levels of price volatility – the least with TOU and the most with real-time pricing. Real-time pricing and CPP tariffs are sometimes referred to as dynamic pricing tariffs since they expose customers to price changes with relatively short or no notice. By contrast, the application of TOU tariff rates is flagged to customers well in advance.

Time-based electricity tariffs can allow for the calculation of different measures of elasticity, each capturing a different dimension of demand responsiveness. For example, if on a two-period TOU tariff the peak rate is increased while the off-peak rate is kept constant, the **own-price elasticity** for peak period electricity refers to percentage reduction in peak demand from a one percent increase in peak price, all other prices being held constant. An elasticity that is (in absolute terms) greater than 1 would indicate that the good in question has elastic demand, while an elasticity (in absolute terms) of less than one would indicate the good is price inelastic. Meanwhile, the **cross-price elasticity** of demand between peak and off-peak periods is the percentage change in the demand for peak electricity resulting from a one per cent change in the price of off-peak electricity. Goods that are *substitutes* tend to have a *positive* cross-price elasticity, whereas goods that are *complements* tend to have a *negative* cross-price elasticity. Finally, the **elasticity of substitution** is defined as the change in relative demand between two periods (e.g. the ratio of the peak demand to off-peak demand) resulting from a one percent change in the inverse of the relative prices in those periods (e.g., the ratio of the off-peak price to the peak price). Since the price term in this definition uses the inverse ratio compared to that used for peak and off-peak demand, estimated substitution elasticities are typically non-negative. For example, it is rare for a decrease in the ratio of off-peak to peak prices (due to an increase in the peak rate and no change in the off-peak rate) to result in an increase in the ratio of peak to off-peak consumption.

Elasticity estimates can be influenced by a range of factors including – the relevant class of user, whether the estimate is for the short term or long term effect, the time period of the analysis, whether price changes are passed through to end-user prices, the length of any peak period, the availability of substitutes, climate differences and locational differences.

Our literature review finds that electricity customers do tend to respond to some extent to time-based tariffs. In particular, it appears that high peak-use tariffs tend to reduce peak-time demand, and residential customers are more responsive to peak-time prices than non-residential customers. Further, these effects are much more pronounced in the long term than in the short term. In some cases, high peak-time tariffs also reduce off-peak demand due to an overall ‘conservation’ effect. However, where this occurs, customers typically still increase the ratio of their off-peak to peak consumption. These results suggest that any restructuring of Transpower’s tariffs will have implications for the economically-efficient use of, and investment in, the transmission network, especially in light of the increasing availability and falling cost of new automated or semi-automated response-enabling technologies.



# 1 BACKGROUND

We have been engaged by Transpower to prepare a review of the elasticity of electricity demand and whether and how it may differ during peak and off-peak periods. Demand elasticity refers to the responsiveness of demand to changes in price. This review will form an input to Transpower's considerations of the role of peak-use charging under the electricity transmission pricing methodology.

This report:

- Outlines the key forms of time-based customer tariffs (chapter 2)
- Defines the various types of demand elasticity measures, explains the significance of different elasticity values and notes why elasticity estimates may vary (chapter 3)
- Summarises the relevant empirical literature on the elasticity of electricity demand, separating study findings according to customer type (residential and non-residential) (chapter 4)
- Concludes with a brief discussion of the implications of demand elasticity for peak-use charging (chapter 5)
- Provides an Appendix that defines various elasticity measures and
- Includes a list of references.

## 2 FORMS OF TIME-BASED TARIFFS

Before embarking on a review of the electricity demand elasticity literature, it is important to understand the types of time-based tariffs most frequently used to generate elasticity estimates.

Time-based tariffs can be classified broadly as time-of-use (TOU) rates, real-time pricing and critical peak pricing (CPP). These rates expose customers to varying levels of price volatility – the least with TOU and the most with real-time pricing. The main features of these different types of tariffs are as follows:

- In **TOU** tariffs the price for energy usage is differentiated by whether consumption occurs in the peak or off-peak period, and possibly a shoulder period as well. The hours of the day that are in the peak, off-peak and shoulder periods, as well as the prices applying in each period, are pre-specified in the tariff. The price differentials between the time periods are an incentive for customers to reduce consumption in the peak period and potentially increase consumption in the off-peak period on a long-term basis.

Seasonal TOU pricing is a variation on this theme where the rates for each pricing period differ during different periods of the year.

- **Real Time Pricing** tariffs link the price of electricity that the customer pays in any hour or half-hour to the wholesale price. Such tariffs are typically only offered to large commercial and industrial customers, although Flick Electric Co offers residential customers a real-time pricing option known as 'Freestyle', in which the retail tariff directly reflects wholesale spot prices<sup>1</sup>.
- **CPP** tariffs include a very high price on a limited number of days each year when the retailer or network operator (as applicable) expects the system to experience an extreme peak demand event. Customers are usually given notice a day ahead that the following day has been declared a critical peak day. Variations of CPP tariffs reflect differences in:
  - the number of days per year that can be called a critical peak day
  - whether or not the starting time and length of the critical peak period is fixed beforehand, and
  - whether or not the critical peak price is fixed beforehand.

Other variations include the amount of information the customer receives about prices and load, and the provision of different types of technologies available to facilitate the response to the price signals.

Real-time pricing and CPP tariffs are sometimes referred to as dynamic pricing tariffs since they expose customers to price changes with relatively short or no notice. By contrast, the application of TOU tariff rates is flagged to customers well in advance. Note that the above characterisation is not exclusive. Some tariffs that have been implemented combine features of two or all of the above three categories, and some combine one or more of the above categories with some form of non-price load management, such as capacity charges or load curtailment.

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<sup>1</sup> See: <https://www.flickelectric.co.nz/freestyle> (accessed 19 September 2018).

## 3 ELASTICITY MEASURES

### 3.1 Types of elasticity measures

Changes to tariffs with time-based rates are likely to have an impact not only on the aggregate level of electricity demand, but also on the shape of the demand profile. For example, if on a two-period TOU tariff the peak rate is increased while the off-peak rate is kept constant, then one would expect a reduction in peak period demand. The amount of reduction in peak demand in this case can be measured by the **own-price elasticity** for peak period electricity.<sup>2</sup>

An elasticity that is (in absolute terms) greater than 1 would indicate that the good in question has elastic demand, while an elasticity (in absolute terms) of less than one would indicate the good is price inelastic. As a relatable example, Khaled and Lattimore (2008) produced a paper that estimated elasticities for consumer spending using the New Zealand Household Expenditure Survey data. They found that the own-price elasticity of food was very small at -0.09, indicating that demand for food is highly inelastic. This means that for a 1% increase in the price of food, the quantity of food purchased decreases by only 0.09%. They also found that housing (rental and owner-occupied housing) and housing operation (power, appliances, floor coverings, household supplies etc.) also have inelastic demands at -0.436 and -0.928, respectively. They also find that transport is very inelastic, at -0.230 (hence the name of the report was “New Zealand’s love affair with houses and cars”). The fact that these expenditure categories are inelastic makes sense, as even if the price rises it is difficult to reduce one’s demand for them because the goods are necessities and have few substitutes. Apparel (clothing and footwear), on the other hand, was found to be very elastic, with an elasticity of -2.207<sup>3</sup>, so that for a 1% increase in price in apparel, the quantity of apparel purchased decreased by 2.207%. In the face of a price rise, customers are much more able to simply purchase less clothing, as this good is not as necessary to daily functioning as is food or housing.

In addition to the reduction in peak period demand, an increase in the peak rate in a two-period TOU tariff would be expected to cause a shift in demand to the off-peak period. The measure commonly used in the literature to summarise the degree of such load shifting is the **cross-price elasticity** of demand between peak and off-peak periods. The **cross-price elasticity** is defined as the percentage change in the demand for electricity in one period resulting from a one per cent change in the price in another period, all other prices staying constant.<sup>4</sup>

Goods that are *substitutes* tend to have a *positive* cross-price elasticity, whereas goods that are *complements* tend to have a *negative* cross-price elasticity. Therefore, cross-price elasticities between peak and off-peak demand would be non-negative to the extent that increasing the price of electricity in the peak period increased demand in the off-peak period as a result of load shifting. For example, a cross-price elasticity of 0.10 would indicate that for a 1% increase in the price of peak electricity, there would result a 0.10% increase in the consumption of off-peak electricity. However, it may also be the case that the cross-price elasticity could be negative, and this would indicate a ‘conservation’ effect whereby increasing the price in the peak period results in a decrease in electricity in the off-peak period,

<sup>2</sup> See Appendix for a formal definition.

<sup>3</sup> Khaled and Lattimore (2008) pp. 140

<sup>4</sup> See Appendix for a formal definition.

likely due to consumers reducing demand as a whole. The larger the magnitude of the cross-price elasticity, the greater the load shifting (if non-negative) or conservation (if negative) effect is.

Several studies present estimates of another measure of price response, the so-called *elasticity of substitution*, which captures a combination of own-price and cross-price responses.<sup>5</sup>

The *elasticity of substitution* is defined as the change in relative demand between two periods (e.g. the ratio of the peak demand to off-peak demand) resulting from a one percent change in the inverse of the relative prices in those periods (e.g., the ratio of the off-peak price to the peak price). Since the price term in this definition uses the inverse ratio compared to that used for peak and off-peak demand, estimated substitution elasticities are typically non-negative. For example, it is rare for a decrease in the ratio of off-peak to peak prices (due to an increase in the peak rate and no change in the off-peak rate) to result in an increase in the ratio of peak to off-peak consumption.

An elasticity of substitution cannot be used on its own to calculate the impact of a price change on demand, since it measures the impact of a relative price change on relative demand. For example, if the elasticity of substitution were 0.14, this would indicate that halving of the ratio of peak to off-peak prices (equivalent to a doubling of the off-peak to peak price ratio) would result in an increase of 14% in the ratio of peak to off-peak consumption. If we assume that the total amount of electricity consumed is unchanged (i.e. no conservation effect), then the elasticity of substitution captures the extent of load shifting that results from a change in relative prices. A more general application of the elasticity of substitution would require information on the change in daily electricity consumption.

## 3.2 Factors influencing elasticity estimates

A number of factors can have a bearing on the estimates of price elasticities found in the literature:

- **Electricity demand is an indirect, or derived, demand:** Electricity users do not demand electricity per se, but rather the end-use services that electricity can provide such as heating, air conditioning, lighting, and so on.
- **Classes of users:** Studies of electricity demand commonly classify users as being residential, commercial or industrial users. Since the uses of electricity, as well as the ability to switch to other sources of energy, differ significantly between these classes of users, one would expect these user classes to respond differently to changes in electricity prices.
- **Short-term and long-term effects:** The response of users to an increase in the price of electricity is also likely to vary over time. Residential users, for example, only change appliances such as water heating units periodically. In the short term, therefore, the response of residential users to an increase in price may be limited because they have little flexibility to change their demand without sacrificing comfort. Over time, however, as more and more households replace their appliances, the response to an increase in price is likely to be larger. For example, when deciding whether to replace their old electric (or gas) hot water heating system, consumers will be in a position to switch their hot water-related demand from electricity to gas or vice versa without incurring high *additional* fixed costs.
- **Time period (i.e. year) of the analysis:** Estimates of the response of users to a change in electricity tariffs may depend on the time period used in the analysis. The uses of electricity, and equipment and appliances change over time. Further, changes in production technology can alter the degree to which alternative energy sources can be substituted for electricity. As a result, the ways in which users are able to respond to a change in electricity tariffs changes over time. Even if recent studies enabled accurate inferences of the responses of electricity users today, the question remains whether these inferences still be accurate in 3 to 5 years' time

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<sup>5</sup> See Appendix for a formal definition.

- **Relationship between network and retail tariffs:** In determining the response of users to a change in electricity tariffs, what matters is the change in the retail tariffs; that is, the tariffs faced by the users. The impact on demand of a change in network tariffs will depend on how these changes are transmitted into the retail tariffs.
- **Size of the price change:** Another factor that affects the response of electricity users is the size of any changes to electricity tariffs. Clearly, a larger change in any element of an electricity tariff will have a larger effect on the use of electricity. But the relationship may not be strictly proportional. While a 10 per cent increase in the price of electricity reduces the demand for electricity by 5 per cent, a 20 per cent increase may reduce demand by 20 per cent.
- **Length of the 'peak' period:** The length or size of the peak period is likely to affect a customer's ability to shift load outside of the peak period, and could change the relative magnitudes of the load shifting and conservation effects. A shorter or narrower peak could result in a larger cross-price elasticity since it is 'easier' (i.e. easier to wait) to shift load to the off-peak period. If the peak period is very wide such that it is more difficult to shift the usage outside of the peak window, consumers may just resort to overall conservation.
- **Availability of substitutes:** Electricity users face large fixed costs when substituting away from electricity to alternatives (such as gas, or self-supply via solar PV plus batteries), or vice versa. For example, if a user has purchased an electric water heater recently, it would most likely take a sizeable and sustained increase in the price of electricity to encourage the household to discard the new electric water heater and purchase a new gas water heater. In this case, a small increase in the price of electricity may have little or no effect. However, an increase in the price of electricity beyond a threshold and for a sustained period would make it attractive to switch to a gas water heater, which would have quite a large impact on electricity demand. Therefore, while the availability of substitutes would be unlikely to affect short-term elasticities (for example, most people don't have both gas and electric options for a given activity in their home), it could heavily affect long-run elasticity estimates. Similarly, the falling cost of solar PV and batteries mean that consumers could elect to self-supply power (either partially or potentially fully via grid defection) instead of purchasing power from the grid. However, it has typically taken a substantial fall in the formerly-high price of self-supply options (via cost reductions and/or subsidies) for customers to consider self-supply as an alternative to grid-sourced power.
- **Climate differences:** Elasticity estimates are likely to differ between different climates. Since heating and cooling often heavily drive electricity demand, in a very warm or very cool climate there may be more scope to reduce or shift load (say, by setting an air conditioning thermostat higher or lower, respectively) than in a more temperate climate, where a customer may only be using electricity for essential purposes such as lighting and cooking.
- **Locational differences:** The location in the world of the studies could affect the types of elasticities likely to be observed, aside from just climate effects. Socio-economic factors, economics factors, availability and types of technology and culture could all affect the way customers consume electricity and respond to price changes.

# 4 REVIEW OF LITERATURE

## 4.1 Introduction

The elasticity literature can be broadly classified into two main streams. The first is a large stream of research which has focused on the demand for electricity without taking into account time-based tariffs and load shifting. This stream includes estimation of the response of demand to changes in average price levels for the purpose of medium to long-term forecasting of electricity demand, as well as earlier studies on the short-term responsiveness of demand prior to the availability of time-based tariff experiments and pilots. The second stream focuses on demand response to TOU pricing and DPP. In this literature review we turn our attention to the latter stream of research.

The TOU literature originated in the mid-1970s as a result of a series of TOU tariff demonstration pilots sponsored by the U.S Federal Energy Administration. These pilots became the subject of a number of econometric research studies of demand response. Since that time, a number of TOU and real-time pricing tariffs have been implemented in the U.S. and elsewhere, and in the last twenty or so years, CPP has also been trialled in a number of countries.

The suite of time-based tariff literature is predominantly concerned with the question of how effective such tariffs are at reducing peak demand through peak reduction, load shifting or conservation. One of the chief quantitative measures of 'effectiveness' is the estimated elasticity(ies), including peak/off-peak own price elasticities, cross-price elasticities (where the 'goods' in question are peak and off-peak consumption), and elasticities of substitution (measured as the ratio of peak and off-peak demand).

Below we discuss estimates of price elasticities for time-based tariffs that have been reported in the international literature. Since these elasticities depend in part on customer characteristics, we discuss the results for the residential sector and the non-residential sectors in separate subsections.

While there are many pilots and studies which aim to analyse the effects of TOU and DPP tariffs, only some of these include econometric estimation of elasticities – we cover these studies in sections 4.2 and 4.3 for Residential and Non-Residential sectors, respectively, and Table 3 and Table 4 summarise the findings.

In section 4.4 we provide a brief summary of the literature around 'peak reduction' (predominantly with reference to Ahmad Faruqui's 2017 meta-analysis) which, despite not having estimated elasticities, still provides useful insight around own-price peak reduction response.

## 4.2 Residential customers

### 4.2.1 TOU tariffs

In 1975 and 1976 the Federal Energy Administration (now United States Department of Energy) implemented 16 demonstration projects to analyse the impacts, customer acceptance and administrative and technical feasibility of TOU tariffs. These projects led to a spate of econometric studies and the first wave of literature surrounding time-based tariffs. Faruqui and Malko (1983) summarise the results for the residential sector for 12 of these projects involving around 7000 customers. Across the suite of projects, they find that the short-run own-price elasticity of demand in the peak period lies between 0 and -0.45, and for the off-peak period the elasticities lie in a similar range

but are less statistically significant<sup>6</sup>. The authors also find that the cross-price elasticity estimates range from 0.17 to -0.67, suggesting that load reduction, as opposed to load shifting, appears to dominate the cross-period relationships. In other words, households react to TOU rates by making wide-reaching decisions such as a thermostat change, rather than actively shifting cooking and other appliance usage between periods<sup>7</sup>.

In addition to geographic, climatic and socio-demographic factors affecting the estimated elasticities, the projects in the study varied widely across a range of metrics including the definition of the peak period, the ratio of peak to off-peak price, the number of different tariffs in the experiment, and the inclusion of a shoulder period. In an attempt to account for such differences, Caves et al. (1984) undertook a simultaneous analysis of five of the mandatory TOU tariff projects. They also allowed for different appliance combinations<sup>8</sup> among customers and climate factors<sup>9</sup>. Caves et al (1984) only report elasticities of substitution rather than total own-price and cross-price elasticities, so we are unable to compare their results directly to those found in Faruqui and Malko (1983). Nevertheless, for a typical customer, Caves et al find that the elasticity of substitution between peak and off-peak consumption in summer is 0.14. This means that a rise in the ratio of peak to off-peak prices has a modestly greater effect on peak demand relative to off-peak demand. This may manifest as an increase in off-peak demand or a smaller reduction in off-peak demand than in peak demand. Further, the study found that in the same climate, a customer with a minimum stock of electrical appliances has an elasticity of 0.07, while a customer whose major appliances are all electric has an elasticity of 0.21<sup>10</sup>. Other conclusions in this study are:

- The substitution elasticity is greater for customers with more appliances.
- The substitution elasticity is slightly smaller in winter than in summer.
- The substitution elasticity is greater in warmer climates.
- There is an interaction between appliance ownership and climatic effects – specifically, the climatic effect is larger for customers with more electrical appliances, and the appliance effect is larger in warm climates.

Baladi et al., (1998) analyse the outcomes of a voluntary TOU experiment conducted by Midwest Power Systems in Iowa. They found that the elasticity of substitution between peak and off-peak consumption varied from 0.127 in May to 0.173 in August<sup>11</sup>. They also compare their results with predictions based on the model developed by Caves et al. based on mandatory TOU tariffs. Baladi et al. obtain very similar results, leading them to conclude that ‘volunteers are not substantially more responsive to TOU pricing than the average residential household’<sup>12</sup>.

Another study of a voluntary residential TOU program is reported in Matsukawa (2001). This study uses data for 279 Japanese households on TOU rates, as well as a random sample of 92 non-TOU households as a control. Consumption data is for the period June 1993 to September 1993. The own-price elasticities reported by Matsukawa range from -0.70 to -0.77 for the peak period, depending on the

<sup>6</sup> Faruqui and Malko (1983), pp. 781

<sup>7</sup> *ibid*, pp. 791

<sup>8</sup> Dummy variables were included for ownership of air conditioning, space heating, clothes dryer, dishwasher, electric oven, etc.

<sup>9</sup> Through the uses of heating and cooling degree days.

<sup>10</sup> Caves et al. (1984), pp. 199-200

<sup>11</sup> Baladi et al. (1998), p.239.

<sup>12</sup> *ibid*

appliance stock, and from -0.51 to -0.72 for the off-peak period<sup>13</sup>. These elasticities are larger than estimates for the U.S., but similar to those of a study done for Swiss households across 40 cities (Filippini, 1995), which reports short-run own-price elasticities of -0.60 and -0.79 for the peak and off-peak periods respectively, and long-run elasticities of -0.71 and -1.92, respectively<sup>14</sup>.

More recently<sup>15</sup>, Colebourn (2006) reports the results of a demand management program implemented by EnergyAustralia. This program – known as the ‘Strategic Pricing Study’ – was developed to examine seasonal TOU tariffs and a selection of CPP tariffs and involved around 1,300 opt-in customers<sup>16</sup>. A series of other TOU and DPP studies were underway at this time in Australia through various other businesses. However, only the EnergyAustralia study resulted in the econometric estimation of elasticities. Colebourn estimates the following elasticities for residential customers<sup>17</sup>:

- A peak own-price elasticity of -0.38 to -0.30 in Summer, and -0.47 in Winter
- A peak to shoulder cross-price elasticity of -0.07 and -0.12 in Summer and Winter, respectively
- A peak to off-peak cross-price elasticity of -0.04 in Summer (no estimate for Winter as no ‘peak’ in Winter)

These results indicate relatively inelastic demand for peak period consumption, slight conservation effects, and larger conservation effects in Winter than Summer.

Filippini (2011) again conducts a study on TOU price elasticities, this time across 22 Swiss cities during the period 2000 to 2006. As with his 1995 study, this study makes use of data obtained from 650 distribution businesses in Switzerland, some of which employ TOU based tariffs. He estimates a short-run own-price elasticity between -0.84 and -0.77 during the peak period, and between -0.75 and -0.65 during the off-peak period. While the magnitudes are similar, this study shows that peak usage is less inelastic than off-peak usage. This is the opposite finding to Filippini’s 1995 study. The short-run cross-price elasticities between peak and off-peak usage are also all positive, indicating that peak and off-peak consumption are substitutes, with a value between 0.79 and 0.92<sup>18</sup>. Long-run own-price elasticities range from -2.27 and -1.61 for the peak period, and -1.652 and -1.273 for the off-peak period, while long-run cross-price elasticities range from 1.77 to 2.31<sup>19</sup>. These results suggest that in the longer term, customers’ TOU demand is relatively elastic and their willingness to target demand reductions in peak periods is relatively high.

In recent years, Ahmad Faruqui has conducted several econometric studies on TOU and DPP tariffs<sup>20</sup>. Two such studies that include elasticity estimates for TOU tariffs have been undertaken in Connecticut (Faruqui et al, 2014) and Ontario (Faruqui et al, 2015):

- The Connecticut study (Faruqui et al, 2014) is a broad study that investigates TOU and DPP for both residential and C&I customers. The study included around 2,200 customers who were randomly assigned to the different tariffs during the summer of 2009. We focus here on TOU residential results. The authors find a substitution elasticity of 0.047<sup>21</sup>. This estimate was unchanged under the ‘tech’ scenario which included an In-Home display of real-time electricity usage and cost information and

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<sup>13</sup> Matsukara (2001), pp. 263

<sup>14</sup> Filippini (1995), pp. 281

<sup>15</sup> ESC (2002) also provides a good summary of the literature pre-2002

<sup>16</sup> Miller (2007), pp. 1

<sup>17</sup> Sergici (2008), pp. 8

<sup>18</sup> Filippini (2011), pp. 5816

<sup>19</sup> *ibid*

<sup>20</sup> See Faruqui & Sergici (2010) and Faruqui, Sergici & Warner (2017)

<sup>21</sup> Faruqui et al (2014), pp. 151



an 'Energy Orb' which is a small sphere that emits different colours based on changes in electricity prices<sup>22</sup>.

- The Ontario study (Faruqui et al, 2015) makes use of data from over 4 million customers and 70 different local distribution companies (LDCs). Beginning in the Summer of 2009, LDCs began defaulting all their regulated rate customers onto a regulated TOU rate under a Government mandate that aligned with the installation of smart meters. The pace and timing of the transition varied by LDC. Because of the non-experimental design of the transition (as compared to many other econometric studies previously conducted), the authors had to take extra steps to ensure estimation robustness<sup>23</sup>. The elasticity of substitution estimates range from 0.12 to 0.27 for Summer, and 0.07 to 0.15 for Winter, and the authors note that "there is significant evidence of load shifting across all LDCs for residential customers, with reductions in usage in the peak and mid-peak periods and increases in the off-peak periods"<sup>24</sup>.

Thorsnes et al (2012) is the only New Zealand-based study we are aware of on TOU rates where estimates of elasticities are calculated. The paper reports on the results of a TOU pricing experiment conducted by the authors and Mercury Energy in Auckland for around 400 participating households. Customers were randomly assigned to four different groups, ranging from no price differential, to 1.25, 1.75 and 3.5 times price differential between peak and off-peak periods. Own-price elasticity estimates were -0.371 for the peak period and -0.0902 for the off-peak period, though the off-peak estimate was not statistically significant<sup>25</sup>. The elasticity of substitution was estimated to be 0.453 and the authors note that a significant pattern of load shifting was observed – that consumption was lower during the peak period and higher in the off-peak period when comparing the experiment year to the previous year<sup>26</sup>.

Simshauser and Downer (2014) in Australia make use of AGL Energy's database of 2.8 billion half-hourly smart meter reads from 160,000 customers in Victoria. The estimation methodology is unclear, but the authors estimate a cross-price elasticity of -0.10<sup>27</sup>.

#### 4.2.2 DPP tariffs

An early study of a dynamic residential tariff is Aubin et al. (1995), which reports on the demand response to a residential CPP tariff trialled by Electricité de France between 1989 and 1992. For customers on this tariff, there are three types of days during the year: 22 red days, 43 white days, and 300 blue days. These days are defined according to three levels of long-run marginal costs, in order above from most to least expensive – with red and white colours approximately corresponding to colder periods<sup>28</sup>. Each of these days is divided into a peak and an off-peak period. The rates applying to each period on any colour day are set ex ante. However, the colour of any day is only announced by 8pm on the previous day via a signal on the customers' meters. The peak to off-peak ratio varies between 1.5 and about 5, while the peak prices increase by more than 10-fold between a blue day and a red day. Participation in the experiment was voluntary. The study reports both own-price and cross-price elasticities. For peak demand, the average own-price elasticity is -0.79 across the three types of days with very little variation between the days. For off-peak demand, the average own-price elasticity is –

<sup>22</sup> *ibid*, pp.140

<sup>23</sup> See Faruqui et al (2015), pp. 40 for list of issues and methods to overcome these issues

<sup>24</sup> *ibid*, pp. 45-46

<sup>25</sup> Thorsnes et al (2012), pp. 558

<sup>26</sup> *ibid* pp. 559

<sup>27</sup> Simshauser and Downer (2014), pp. 212

<sup>28</sup> Aubin et al. (1995), pp. S174. Note, marginal cost in this instance reflects generation (not just network) cost differences.

0.28, ranging from  $-0.23$  for the red days to  $-0.37$  for the less critical blue and white days. The cross-price elasticities are also negative, and in some cases quite large ( $-0.93$ )<sup>29</sup>. This suggests that on critical days, there is a considerable amount of conservation throughout the day. The authors report, however, that the elasticity of substitution is still positive, so that a degree of load-shifting also occurs within the overall conservation effect.

Braithwait (2000) investigates CPP tariffs alongside the inclusion of an interactive communication device that pre-schedules certain major energy-using devices. They find elasticities of substitution ranging from 0.3 to 0.4, depending on the estimation method used and note that this is around twice the magnitude found in previous literature – likely due to the interactive communications equipment<sup>30</sup>.

Probably the best-known study of CPP tariffs is the Californian Statewide Pricing Pilot (SPP). The SPP involved 2,500 customers and ran from July 2003 to December 2005. For the retail sector there was one TOU tariff, a fixed-period (and day-ahead notification) (CPP-Fixed) and a variable-period (day-of notification) CPP (CPP-Variable) tariff. CPP-Variable customers also had the option of having an enabling technology installed free of charge to help facilitate demand response. The sample size for the TOU tariff was relatively small, and according to the final report: ‘Drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP sample sizes’<sup>31</sup>. Hence, we have not reported the estimated elasticities for TOU elasticities in the TOU tariff section above. The overall substitution elasticity estimates for the CPP-Fixed trial were 0.076 for Summer<sup>32</sup> and 0.025 for Winter<sup>33</sup>. For the CPP-Variable trial, the elasticity of substitution ranges from 0.091 to 0.11<sup>34</sup>. The results for ‘technology impact’ across the various trials are an estimate of the impact of having smart (i.e. controllable) thermostats that can respond automatically to the critical price signal. The magnitudes of these coefficients cannot be compared to the elasticities as they are estimated independently of the elasticities and are constant across different price levels. However, the fact that they are statistically quite significant indicates that technology can play an important role in enhancing the demand response to price-based tariffs<sup>35</sup>.

In 2007, SummitBlue Consulting released a report that analysed the results from the New Jersey Public Service Electricity and Gas (PSE&G) myPower CPP pilot program. The study included 379 customers who took part in the myPower Sense program and 319 customers who participated in the myPower Connection program. Those in the Connection program were given programmable thermostats that could respond to TOU and CPP pricing tiers. Summer CPP peak prices were increased 8-fold, while Winter CPP peak prices were roughly doubled. The estimated substitution elasticity for those customers on the myPower Connection program was 0.125, while the substitution elasticity for those on the myPower Sense program (i.e. without technology) was roughly half that value at 0.063<sup>36</sup>.

As noted above, Faruqui undertook several analyses during the 2010s. We consider those CPP studies where elasticities were estimated. There are three such studies:

- Faruqui and Sergici (2011) analyse the results from the Baltimore Gas and Electric Company (BGE) CPP pilot – the ‘Smart Energy Pricing’ (SEP) pilot – that ran during the Summer of 2008 and included

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<sup>29</sup> *ibid*, pp. S187

<sup>30</sup> Braithwait (2002), pp. 371

<sup>31</sup> CRA (2005) pp. 8

<sup>32</sup> *ibid*, pp. 59

<sup>33</sup> *ibid*, pp. 83

<sup>34</sup> *ibid*, pp. 104

<sup>35</sup> *ibid*, pp. 107

<sup>36</sup> SummitBlue (2007), pp. 19

around 1300 residential customers. They find an elasticity of substitution of 0.096 without technology, 0.136 with the 'Energy Orb' (see above TOU section Faruqui et al, 2014) and 0.18 with both the 'Energy Orb' and A/C cycling switch designed to cycle the A/C on and off during the peak period<sup>37</sup>.

- Faruqui et al (2013) focus on a CPP pilot in Michigan in the Summer of 2010, implemented and run by Consumers Energy, called the 'Personal Power Plan' (PPP). This pilot included 921 residential customers and called six critical peak pricing dates. The estimated substitution elasticity was 0.107 which is slightly higher than that found in the 2011 Baltimore study. However, unlike in the 2011 Baltimore study and the 2014 Connecticut study, the substitution elasticity did not vary with and without the enabling technology.
- In addition to TOU tariff elasticity estimates reported in Section 4.2.1 above, the Faruqui et al (2014) study in Connecticut also reports elasticities for a CPP tariff under the same experiment but with ten critical peak days called where the peak price was roughly 4 times the non-CPP day peak-price. The substitution elasticities for the CPP experiment are 0.081 for no technology and with the 'Energy Orb' and 0.128 with the full suite of technology<sup>38</sup>.

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<sup>37</sup> Faruqui and Sergici (2011), pp. 100

<sup>38</sup> Faruqui et al, (2014), pp. 151

### 4.3 Non-residential customers

An early but seminal paper on Commercial/Industrial customer responses to TOU tariffs is a study by Aigner and Hirschberg in 1985. The study focuses on an experiment conducted by Southern California Edison Co. over the period 1980-1982 involving 650 randomly selected large commercial/industrial customers with Summer maximum demands between 20kW and 500kW. Two sub-experiments were conducted – one with TOU energy (kWh) rates, and one with TOU demand (kW) rates. For each experiment, three sets of rates were tested – a small difference in peak and off-peak rates, a moderate difference and a large difference. The results are presented in Table 1. Elasticities of substitution are often statistically insignificant, and even when significant are usually small in magnitude. All have the expected sign except for the Energy tariff for customers with Summer demands in the range 0-50kW, which exhibits a negative elasticity of substitution estimate.

Table 1: Elasticity of substitution estimates by kW Demand Level, Season and Rate type

Rate structure	kW Demand category	Season	Elasticity of substitution	Statistically significant?
<b>Demand</b>	0-50kW	Winter	-0.02	No
		Summer	0.09	Yes
	50kW-200kW	Winter	0.16	Yes
		Summer	-0.05	No
	200-500kW	Winter	0.08	No
		Summer	0.11	Yes
<b>Energy</b>	0-50kW	Winter	-0.04	No
		Summer	-0.06	Yes
	50kW-200kW	Winter	-0.03	No
		Summer	0.07	Yes
	200-500kW	Winter	-0.00	No
		Summer	-0.03	No

Source: Aigner and Hirschberg (1985) pp 352

Goldman et al. (2007) used data from several programs in the U.S., including the SPP in California, to estimate elasticities for five different non-residential customer segments; commercial/retail, government/education; healthcare; manufacturing; and public works. There are two programs analysed in this study that yield elasticity estimates. The first is the Optional Hourly Pricing program which applies to customers with peak demand <1500kW and between 1998-2002. This program offers a two-part rate structure where there is a baseline rate on an agreed baseline load, and a higher rate for any incremental demand above this baseline load. The second is the Default Hourly Pricing program which applies to customers with peak demand > 2000kW and between 2000-2004. This program includes a demand and/or volumetric charge indexed to a day-ahead wholesale market price. Table 2 presents the elasticity of substitution estimates derived in the study. The elasticities reported in Table 2 are overall not

dissimilar to their U.S. residential counterparts. Manufacturing appears to be the most price sensitive customer segment, with other segments more or less price sensitive depending on the program.

Table 2: Average elasticity of substitution estimates

Customer market segment	Optional Hourly Pricing (<1500kW peak demand)	Default Hourly Pricing (>2000kW peak demand)
Commercial/retail	0.01	0.06
Government/education	0.01	0.10
Healthcare	0.01	0.04
Manufacturing	0.26	0.16
Public works	0.07	0.02

Source: Goldman et al. (2007), Table ES-2

In addition to residential elasticities in the EnergyAustralia pilot, Colebourn (2006) also estimates Business peak, own-price elasticities for customers with less than 40MWh of annual energy consumption, and those between 40MWh and 160MWh of annual energy consumption. The elasticity estimates for both categories of Business customers, in both Summer and Winter are not statistically significant.

Finally, the extensive study by Faruqi et al (2014) already referenced for TOU and CPP elasticity estimates for residential customers also reports results for small C&I customers. The elasticity of substitution estimates for the TOU rate structure with and without technology are both statistically insignificant, whereas the elasticity estimates for the CPP tariff structure were significant, but small, at 0.016 without technology and with the 'Energy Orb' and 0.042 with full technology<sup>39</sup>. This suggests that as technologies such as automated controls become cheaper and more widespread, the responsiveness of demand to price changes and differentials should increase.

<sup>39</sup> Faruqi et al (2014) pp.152

## 4.4 Peak response

The above sections in this chapter focus only on TOU and DPP literature that contains econometric estimates of elasticities. However, there are a large number of pilots and associated studies where elasticities are not measured, but that estimate the absolute size of peak demand reductions resulting from various-sized price changes. This section looks at the findings of the most comprehensive meta-analysis of time-based tariff pilots – a paper by Faruqui et al, released in 2017<sup>40</sup>.

Faruqui, Sergici and Warner have, over time, built a database that houses the results from time-based tariff pilots around the globe. They call their database ‘Arcturus’ since the results when charted take the form of arcs of price response (see below). The database contains 337 treatments from 632 pilots beginning as early as 1997 and up to 2017<sup>41</sup>. Only pilots that adhere to rigorous standards of experimental research design are added to the database.

In an earlier presentation to the ACCC/AER regulatory conference in 2014, Faruqui presented two very useful summary charts of the studies within his database up to that time<sup>42</sup>. They are shown in the figures below. Figure 1 shows the peak reduction figure from each time-varying tariff treatment (each bar is a treatment), split by the type of time-varying tariff. Unsurprisingly, in general, the peak reduction is greater under a CPP tariff, than a TOU tariff. The peak reduction under TOU is fairly modest across the majority of treatments, while the peak reduction under CPP for the majority of treatments is quite substantial. Figure 2 displays the same information with a scatterplot and price response ‘arc’, but with the addition of whether the treatment included technology or did not. It is clear from these charts that the price response under both TOU and CPP tariff structures is larger when the treatment includes assisting technology. However, it is important to reemphasise that these responses are not estimates of demand elasticity, but rather they are estimates of absolute demand reductions under different tariff structures.

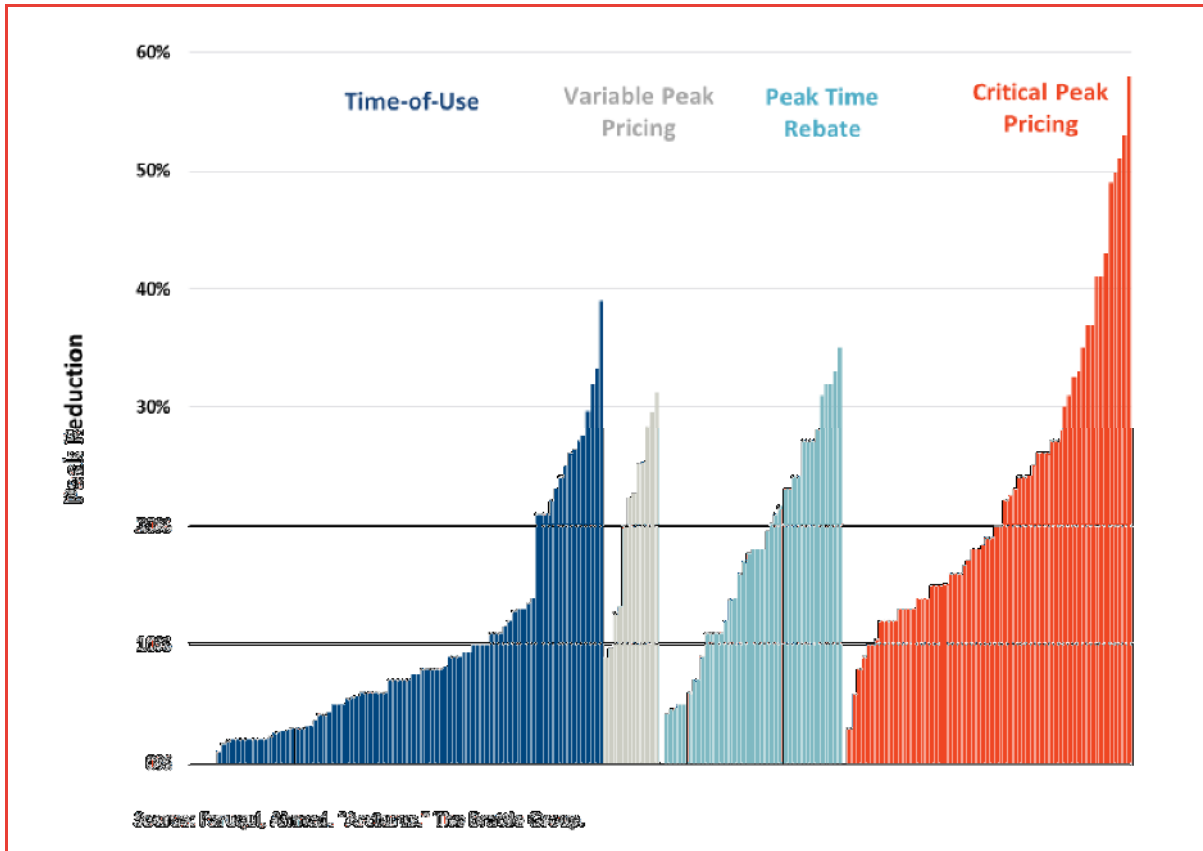
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<sup>40</sup> The 2017 paper is for Arcturus 2.0. An earlier paper was released by Faruqui and Sergici in 2013 for Arcturus 1.0.

<sup>41</sup> A full list of the pilots, their year and jurisdiction and the type of rate study can be found in Appendix A of the paper

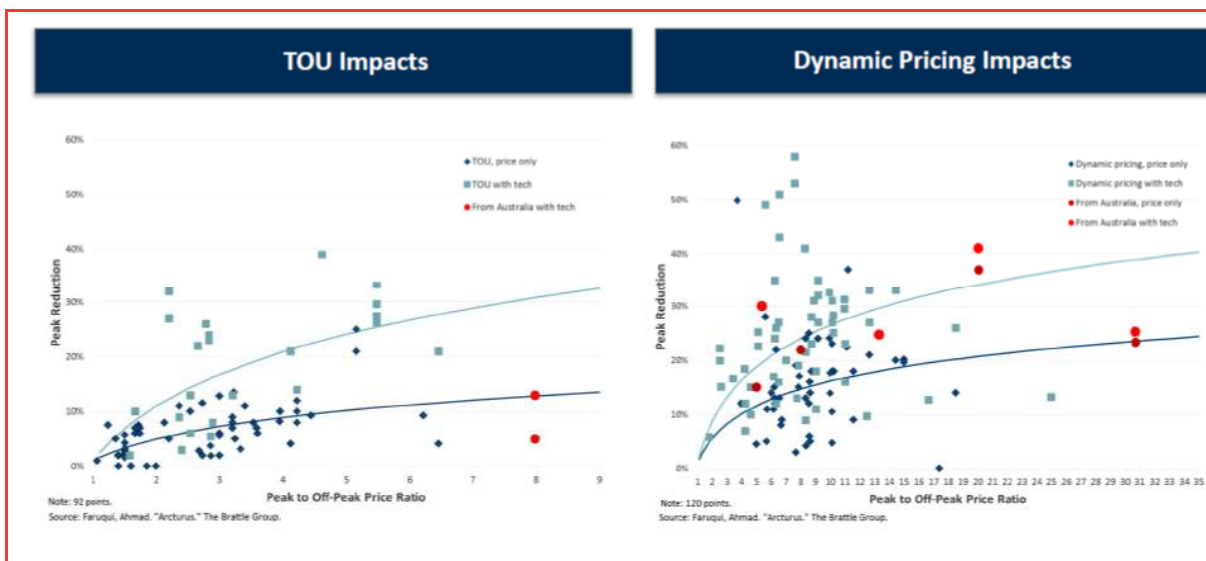
<sup>42</sup> This would reflect the Arcturus 1.0 database, as in Faruqui and Sergici (2013)

Figure 1: Peak demand reduction percentages under various time-based tariff pilot studies



Source: Faruqi, 2014, Presentation to ACCC/AER Regulatory Conference

Figure 2: Peak demand reductions under various time-based tariff pilot studies – price response arcs denote with and without assisting technology



Source: Faruqi, 2014, Presentation to ACCC/AER Regulatory Conference

Table 3: Summary of elasticities literature – Residential

(Square brackets denote lower and upper bounds of estimate, respectively; results only presented where statistically significant at 5%)

Study	Type	Jurisdiction	Elasticities	Comments
<b>Faruqui and Malko, 1983</b> pp. 790-791	TOU	U.S. Various	Short Run Own-Price, Peak: [-0.44, 0] Short Run Own-Price, Off-Peak: [-0.45, 0] Short Run Cross-Price: [-0.67, 0.17]	Lots of variability in estimates due to variation in rate level, peak period, climate, appliance usage etc.  Faruqui (2017) notes questionable statistical quality of experiments.
<b>Caves et al, 1984</b> pp. 198	TOU	U.S. Various	Elasticity of Substitution: 0.14 Range: [0.07, 0.21] for minimal and all major electrical appliances, respectively Range: [0.12,0.15] for cool and hot climates, respectively	Price ratios vary across the 5 assessed experiments from 8:1 to 16:1. Various peak times of day, ranging from narrow to wide
<b>Filipini, 1995</b> pp. 281	TOU	Switzerland	Short Run Own-price, Peak: -0.60 Short Run Own-price, Off-peak: -0.79 Long Run Own-price, Peak: -0.71 Long Run Own-price, Off-peak: -1.92	Partial elasticities Covers 40 cities in Switzerland --> variable peak time of day and peak-to-off peak price ratios
<b>Baladi et al, 1998</b> pp.238-239	TOU	Iowa	Elasticity of Substitution: [0.127, 0.173], May is lower bound and August is upper bound	Partial elasticities. Peak from noon-7pm, weekdays Peak-OP prices 4.6:1
<b>Matsukawa, 2001</b> pp.263	TOU	Japan	Own-price, Peak: [-0.77, -0.70] Own-price, Off-peak: [-0.72, -0.51]	Peak period: 7am-11pm Price ratio ranges from 2.4:1 to 3.7:1



Study	Type	Jurisdiction	Elasticities	Comments
<b>Colebourn, 2006</b>	TOU	Australia	Own-price, Peak: [-0.38, -0.30] Summer, -0.47 Winter Cross-price, Shoulder: -0.07 Summer, -0.12 Winter Cross-price, Off-Peak: -0.04 Summer	Obtained from Sergici (2008), pp.8
<b>Thorsnes Williams &amp; Lawson, 2012</b> pp. 558	TOU	New Zealand	Own-price, Peak: -0.371 Own-price, Off-Peak: Not significant Elasticity of Substitution: 0.453	Price ratios ranging up to 3.5:1. Peak period 7am-7pm weekdays
<b>Filipini, 2011</b> pp. 5816	TOU	Switzerland	SR, Own-price, Peak: [-0.84,-0.77] SR, Own-price, Off-Peak: [-0.75,-0.65] LR, Own-price, Peak: [-2.26,-1.60] LR, Own-price, Off-Peak: [-1.65,-1.27]	Usually from 7am-9pm, weekdays
<b>Faruqui et al, 2014</b> pp. 151	TOU	Connecticut	TOU Elasticity of Substitution: 0.047 with and without tech	12pm-8pm weekdays, variety of price ratios
<b>Simshauser and Downer, 2014</b> pp.212	TOU	Australia, Victoria	Cross-price: -0.10 (i.e. load conservation, rather than shifting)	3pm-9pm peak Unclear how elasticity was estimated
<b>Faruqui, et al, 2015</b> pp.46	TOU	Ontario	Elasticity of Substitution, Summer: [0.12, 0.27] Elasticity of Substitution, Winter: [0.07, 0.15]	Price ratio 1.9:1. Peak period: Summer 11am-5pm, Winter 7am-11am and 5pm-7pm
<b>Aubin et al, 1995</b> pp.S186-187	CPP	France	Own-price, Peak: -0.79 Own-price, Off-Peak: [-0.37, -0.23] Cross-price: -0.93	Peak is 7am-11pm (or 1am on 'red' days)

Study	Type	Jurisdiction	Elasticities	Comments
<b>Braithwait, 2000</b> pp.371	CPP	New Jersey	Elasticity of Substitution: [0.30,0.40]	Larger estimate (compared to say, Caves et al. 1984) attributed to presence of interactive equipment for customers to present usage of AC and appliances
<b>CRA, 2005</b> pp.59,83,104	CPP-F CPP-V	California	Elasticity of Substitution Summer: 0.076 Elasticity of Substitution Winter: 0.025 Elasticity of Substitution: [0.091, 0.11]	A vast array of elasticities estimated for different structured tariffs
<b>Summit Blue, 2007</b> pp.19	CPP	New Jersey	Elasticity of Substitution: 0.063 with no tech, 0.125 with tech	Peak CPP price roughly 8 times the standard price in Summer, and 2.5 times the standard price in Winter
<b>Faruqui et al, 2011</b> pp.100	CPP	Baltimore	Elasticity of Substitution: 0.096 no tech, 0.136 with 'Orb' and 0.18 with full tech	At time of CPP price raised 9 times the standard rate.
<b>Faruqui et al, 2013</b> pp.581	CPP	Michigan	Elasticity of Substitution: 0.107 with or without tech	Peak period: 2pm-6pm weekdays. CPP/Peak/OP ratio approx. 7:2:1
<b>Faruqui et al, 2014</b> pp. 151	CPP	Connecticut	Elasticity of Substitution: 0.081 with no tech or 'Orb', 0.128 with full tech	Peak price roughly quadrupled on CPP days

Source: *Frontier Economics review of literature*

Table 4: Summary of elasticities literature – Non Residential

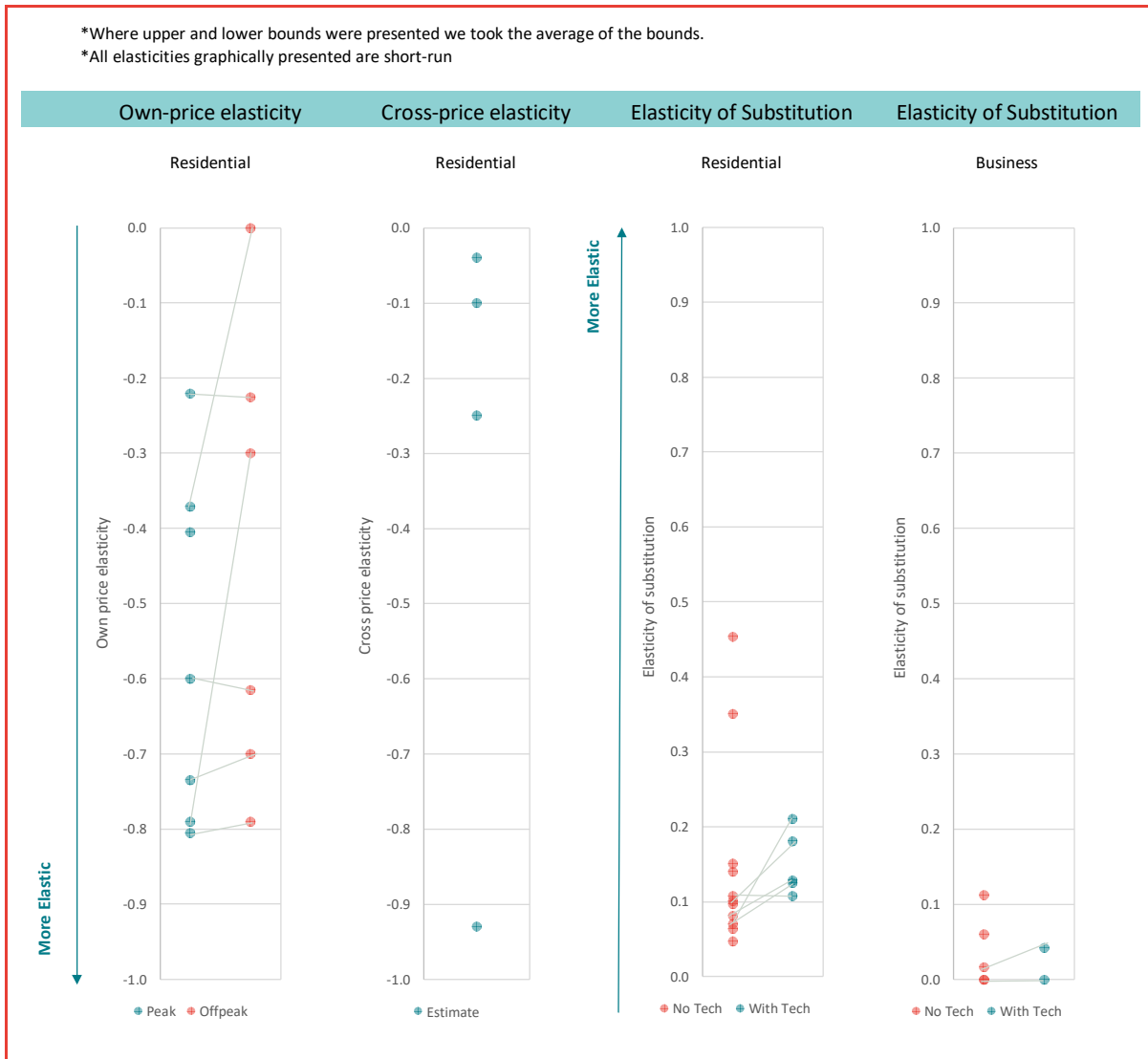
(Square brackets denote lower and upper bounds of estimate, respectively; results only presented where statistically significant at 5%)

Study	Type	Jurisdiction	Elasticities	Comments
<b>Aiger and Hirshberg, 1985</b> pp.352	TOU	California	Brackets below represent: (50kW, up to 100kW, up to 500 kW demand) <b>Demand</b> Elasticity of Substitution: Winter: (Not Significant, 0.16, Not Significant) Summer: (0.09, Not Significant, 0.11) <b>Energy</b> Elasticity of Substitution: Winter: (Not Significant, Not Significant, Not Significant) Summer: (-0.06, 0.07, Not Significant)	Peak period: 12pm-6pm Summer, 5pm-10pm Winter, weekdays. Price ratio ranging from 3:1 to 9:1.
<b>Colebourn, 2006</b>	TOU	Australia	Own-price, Peak, <40MWh: Not significant Own-price, Peak, 40MWh-160MWh : Not significant	Obtained from Sergici (2008), pp.8
<b>Goldman, 2007</b> pp.xi	CPP	U.S. Various	Elasticity of Substitution <1500 kW peak demand: [0.01,0.26] Elasticity of Substitution >2000 kW peak demand: [0.02,0.16]	Varying by industry. Most industries very inelastic, manufacturing at the upper bound of estimates.
<b>Faruqui et al, 2014</b> pp. 152	TOU	Connecticut	Small C&I Elasticity of Substitution: Not significant with and without tech	12pm-8pm weekdays, variety of price ratios
<b>Faruqui et al, 2014</b> pp. 152	CPP	Connecticut	Small C&I Elasticity of Substitution: 0.016 without tech and with Energy Orb, 0.042 with full tech	10 critical days called, applying CPP to 2-6pm on these days

Source: *Frontier Economics review of literature*

Figure 3 graphically represents a summary of the short-run estimates in the literature for elasticities of substitution, cross-price elasticities and own-price elasticities. The lines connecting dots represent estimates obtained from the same study.

Figure 3: Graphical summary of short-run price elasticities



Source: Frontier Economics visual representation of summary of literature

What the four elements of this diagram shows is that:

- There are mixed results in the studies as to whether residential peak-demand is more price inelastic (less price responsive) or less price inelastic (more responsive) than off-peak demand, though it is clear that demand is relatively inelastic in both TOU periods.
- An increase in peak-usage charges for residential consumers will reduce peak-demand, but will also have an indirect (lesser) impact of reducing off-peak demand e.g. some initiatives that reduce peak demand reduce total demand as customers respond with overall conservation of energy in response to the peak price increase.

- Residential elasticity of demand substitution is relatively low (typically around 0.1 without technology, or 0.1 – 0.2 with technology assisting and encouraging a demand response). What this means is that a 50% reduction of the ratio of peak to off-peak prices (equivalent to a doubling of the off-peak to peak price ratio – i.e. peak consumption becomes relatively cheaper) would result in an increase of only 10% in the ratio of peak to off-peak consumption
- Business demand is more inelastic than residential demand (less price responsive), with substitution elasticities ranging from 0.0 (unresponsive) to about 0.1.

## 5 POTENTIAL IMPLICATIONS

Our review finds that:

- While it is clear that demand for electricity is inelastic, the literature remains mixed as to whether peak periods are more elastic than off-peak periods, or vice versa.
- High peak-use tariffs tend to reduce peak-time demand, and residential customers are more responsive to peak-time prices than non-residential customers.
- Consumer responses to peak-use tariffs are much more pronounced in the long term than in the short term.
- Demand response effects are much greater where automated or semi-automated response-enabling technologies have been applied. It is reasonable to infer that technological change will result in demand for electricity being more flexible, and responsive to price signals.
- In some cases, high peak-time tariffs also reduce off-peak demand due to an overall 'conservation' effect. However, where this occurs, customers typically still increase the ratio of their off-peak to peak consumption. The overall affect is a slight flattening of load profile.

These findings suggest that peak-use charging deters peak-time demand and helps with flattening load profiles.

In the context of any tariff restructuring of Transpower's charges, the effect of any reduction in peak-use tariffs would need to be assessed in combination with an increase in some other tariff(s) component(s) used to ensure revenue recovery neutrality. In particular, while a reduction in peak-use tariffs is likely to result in an increase in peak-time demand relative to any alternative, it is difficult to confirm whether a reduction in peak-use tariffs will result in a net reversal of any overall conservation effects and if so, whether this effect would persist in the longer term. This will have implications for the economically-efficient use of, and investment in, the transmission network, especially as the penetration of new technologies increases over time.

# APPENDIX

## Elasticity measures

### Own-price elasticity of demand

The *own-price elasticity* of demand is the percentage change in the demand for a commodity resulting from a one percent change in its price, all other prices staying constant.

In the context of a two-period TOU tariff, if the peak rate is increased while the off-peak rate is kept constant, the own-price elasticity for peak period electricity can be described as follows:

$$\varepsilon_p = \frac{\delta C_p / C_p}{\delta p_p / p_p} = \frac{\delta C_p p_p}{\delta p_p C_p}$$

Where  $C_p$  defines the consumption of electricity in the peak ( $p$ ) period and  $p_p$  denotes the price of electricity in the peak period.

An elasticity that is (in absolute terms) greater than 1 would indicate that the good in question has elastic demand, whereas an elasticity (in absolute terms) of less than one would indicate the good has inelastic demand.

### Cross-price elasticity of demand

The *cross-price elasticity* of demand is defined as the percentage change in the demand for one commodity resulting from a one per cent change in the price in another commodity, all other prices staying constant.

In the context of a two-period TOU tariff, the cross-price elasticity of off-peak demand to the peak price refers to percentage change in the demand for electricity in the off-peak period resulting from a one percent change in the price of electricity in the peak period, all other prices staying constant. This can be described as follows:

$$\varepsilon_{op,p} = \frac{\delta C_{op} / C_{op}}{\delta p_p / p_p} = \frac{\delta C_{op} p_p}{\delta p_p C_{op}}$$

Where  $C_{op}$  defines the consumption of electricity in the off-peak ( $op$ ) period and  $p_{op}$  denotes the price of electricity in the off-peak period.

Goods that are *substitutes* tend to have a *positive* cross-price elasticity (that is, an increase in the price of one increases the demand for the other), whereas goods that are *complements* tend to have a *negative* cross-price elasticity (that is, an increase in the price of one reduces the demand for the other).

### Elasticity of substitution

The *elasticity of substitution* is defined as the change in relative demand between two commodities resulting from a one percent change in the inverse of their relative price, all other prices staying constant.

In the context of a two-period TOU tariff, the elasticity of substitution refers to the percentage change in the ratio of demand between two periods (e.g. the ratio of peak demand to off-peak demand) resulting from a one percent change in the inverse of the relative prices in those periods (e.g., the ratio of the off-peak price to the peak price). This can be described as follows:

$$E_{op,p} = \frac{\left( \frac{\delta(C_p/C_{op})}{C_p/C_{op}} \right)}{\left( \frac{\delta(p_{op}/p_p)}{p_{op}/p_p} \right)}$$

Since the price term in this definition uses the inverse ratio compared to the ratio of peak and off-peak demand, estimated substitution elasticities are typically non-negative. For example, it is rare for a decrease in the ratio of off-peak to peak prices (due to an increase in the peak rate and no change in the off-peak rate) to result in an increase in the ratio of peak to off-peak consumption.



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**frontier economics**

BRISBANE | MELBOURNE | SINGAPORE | SYDNEY

Frontier Economics Pty Ltd  
395 Collins Street Melbourne Victoria 3000

Tel: +61 (0)3 9620 4488

[www.frontier-economics.com.au](http://www.frontier-economics.com.au)

ACN: 087 553 124 ABN: 13 087 553

## Attachment C

### **Impact of removing peak pricing on transmission investment Transpower as the Grid Owner, October 2018**

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#### **Overview and summary of findings**

The objective of our analysis is to test the potential impact removing peak pricing from the Transmission Pricing Methodology (TPM) could have on transmission investment timing and cost.

We have tested the potential impact by using future expected investments in the North and South Islands as case studies.<sup>20</sup> We considered how each investment's need date might be impacted by removal of the existing price incentive on Electricity Distribution Businesses (EDBs) to use load control to limit their offtake from the grid during regional peaks. Or said another way, by an increase in peak demand resulting from a loss of load control by EDBs when demand for electricity is high.

#### **Conservative approach taken**

We have been purposely conservative and tested only modest peak demand growth (modest reductions in EDB load control at peak). We have not considered the potential impact on behaviour of embedded generators or consumers who currently also respond to RCPD. Neither have we considered the costs emanating from stranding risk reflecting heightened uncertainty of future demand for transmission services.

The results should consequently be treated as the lower bounds of the potential impacts of removal of RCPD on transmission investment timing and cost, and indicative of direction.

#### **Summary of findings**

The case studies show that RCPD has a material impact on Transpower's investment requirements, even if RCPD is assumed to only have modest impacts on EDB load control, and the peak demand forecast we use to determine the timing of future investment needs (need date):

- If removal of RCPD increases EDB peak demand by 3% we expect to bring forward the analysed projects by 2 years (and increase project costs by 8%).
- If EDB peak demand increases by 7% the analysed projects are brought forward by 4 to 6 years (and increase project costs by up to 16%).

#### **Issues that may arise from reduction in load control**

Two main issues may arise from increased peak demand due to a reduction in EDB load control:

- Advancing projects that have already been identified as solutions to grid issues. Particularly, those that are driven by load (demand) such as voltage stability concerns and other issues identified in our 15-year ahead Transmission Planning Report (TPR); and
- Advancing grid issues that are outside of the TPR timeframe and do not have identified solutions at this point in time.

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<sup>20</sup> The case studies were selected on the basis that they were relatively straightforward to analyse. Other projects that could have been investigated would have required more time and resource than was available for completion of this report.

Given the time and resources available we have necessarily focussed on interconnection asset needs identified in the TPR (the first category above).

## Methodology

The analysis performed was separated into a South Island portion and a North Island portion using selected future expected investments as case studies.

We focussed on projects with need dates directly impacted by peak demand and requiring material investment in interconnection assets. The analysis was not completed for the existing Enhancement and Development (E&D) portfolio due to the complexity of analysing a wide scope of projects with varying drivers and characteristics. Customer driven supply projects, typically for connection assets, were also omitted as there are other significant factors that influence the need dates and strategies for these types of projects.

We considered EDB-connected winter peak demand (when the principal peak demand occurs), excluding grid exit points (GXPs) materially influenced by large industrial load or embedded generation. We estimated EDB load control used at peak to manage transmission charges based on information collected in 2016 for a Transpower-commissioned study by Scientia Consulting.<sup>21</sup>

Increases in EDB load of 3% and 7% were added to the prudent forecast of peak demand. The scaling was performed on the winter island peak prudent forecast of peak demand for TPR 2017.<sup>22</sup> We set these scaling factors conservatively (low) given we had limited information available at the time for a more robust approach.

Subsequently we were able to test the veracity of our assumptions against EDB's emerging technology data, released by Commerce Commission 10 October 2018 – refer to Appendix A. We consider the comparison, summarised in the table below, shows the modelled EDB load control impact on peak demand of 3% and 7% are credible and likely very conservative (low).

**Table C1: 2018 loads, and 2018 loads with 3% and 7% increases**

	2018 Peak Demand Forecast (TPR-2017)	Load control estimate at 3%	Load control estimate at 7%	Load control capacity from ripple control, avg 2014-2018	Load control relative to maximum coincident peak demand 2018
Case Study 1	1,111 MW	+ 33 MW	+ 78 MW	+ 269 MW	20.2%
Case Study 2	2,285 MW	+ 78 MW	+ 181 MW	+321 MW	19.2%

<sup>21</sup> Embedded Generation and Gross Demand Analysis (July 2016) by Scientia Consulting. [Transpower - Appendix G1: https://www.ea.govt.nz/dmsdocument/21133](https://www.ea.govt.nz/dmsdocument/21133). We commissioned the study in response to a previous Authority proposal to remove peak pricing from the TPM.

<sup>22</sup> We also adopted a conservative approach by excluding potential Distributed Generation impacts. We focussed on EDB's load control because EDBs have no commercial incentive to respond to energy prices.

To determine the total advancement of a load driven project, we followed the process below:

1. The total peak demand forecast in the region of interest at the project's need date was assumed to be the peak demand trigger for the project. In reality, the peak demand trigger would be less than this value, but higher than the previous year's forecast. Therefore, there may be an error with the potential to bring forward the need date by up to one more year.
2. The EDB load in the area of interest was then scaled and compared to the peak demand forecast throughout the study timeframe to find when the scaled peak demand exceeded the area trigger determined in step 1.<sup>23</sup>

Once the need date shift difference was identified, the cost of advancement was computed to bring the project forward from the need date identified in step 1 to the need date identified in step 2.

## Case Study 1. Upper South Island voltage stability

A major issue with a need date that is highly driven by the magnitude of peak demand is the Upper South Island (USI) voltage stability issue.

The issue has been discussed fully in the grid backbone section of the TPR and has been the subject of much system planning analysis. The voltage stability of the USI is directly impacted by the magnitude of peak demand in the area.

Based upon previous analysis, it was identified that two new switching stations are needed to alleviate voltage stability concerns, with summer issues starting in 2027 and winter issues in 2028. The winter peak, non-industrial prudent load forecast can be scaled up to determine when the scaled winter loading level exceeds the unscaled 2028 winter load levels.

When the EDB winter load in the USI is scaled up by 3%, the need date of the new switching stations is advanced by approximately 2 years from summer 2027 to winter 2025. When the EDB winter load in the area is scaled by 7%, the need date of the new switching stations is advanced by approximately 4 years from summer 2027 to winter 2023. The indicative cost of such a project is around \$44.2 million.<sup>24</sup>

Detailed cost estimates have not been obtained at this stage for this new switching station. However, a high-level approach can be taken to estimate the cost of this advancement. The way Transpower traditionally evaluates the high-level advancement cost is to assume the indicative cost is the future value of the project cost. Then, the cost is brought back to the present day at a discount rate of 7%.

When this approach is applied to this project, the high-level cost of advancing the switching station construction from 2027 to 2025 (3% scaling) is estimated to be approximately \$3.5 million and the cost of advancing the switching station from 2027 to 2023 is \$7.5 million (7% scaling).

<sup>23</sup> Refer to Appendix A.

<sup>24</sup> Orari Switching Station – Solution Study Report (March 2013) by AECOM. Indicative project cost in \$2018.

## Case Study 2. Waikato and Upper North Island voltage stability

The North Island grid backbone is much more complicated to analyse (than the South Island) since the development plans are highly dependent upon the location of future generation. One significant exception to this is the Waikato and Upper North Island (WUNI) voltage stability project.

Although this project is also impacted by the location of future generation, the impact of load control reduction (peak demand growth) can be addressed at a high level. Presently, this area is under study and several development plans are being evaluated which makes evaluating the impact of a change in load control philosophy quite cumbersome. However, there are certain system upgrades that have been identified as more or less common to all prospective development plans, and so are conducive to this analysis.

The WUNI project is similar to the USI project in that it is predominately driven by the magnitude of peak demand. Additional peak demand in the area will have a significant impact on the need dates of these common system upgrades.

The following table highlights the system upgrades common to all currently identified development plans, their need dates under the existing winter prudent forecast and with a 3% and a 7% increase in the prudent forecast for non-industrial winter peak load. It should be noted that these projects are not approved at this time but have been selected to illustrate the impact peak demand increase may have. Additionally, the indicative costs are estimated and subject to change. We have not yet obtained detailed cost estimates for the identified WUNI upgrades.

**Table C2: System upgrades common to development plans for Waikato and Upper North Island project**

System Upgrade	Need date TPR-2017 prudent forecast	Need date with 3% increase	Need date with 7% increase	Indicative Upgrade Cost (\$M) <sup>25</sup>
Upgrade 1	2027	2025	2023	58
Upgrade 2	2030	2028	2025	155
Upgrade 3	2034	2032	2028	33
Upgrade 4	2038	2036	2032	32
Upgrade 5	2041	2039	2035	33

When performing the same cost of advancement analysis as described in the South Island results section, the high-level cost of advancing the base WUNI upgrades from their original need date to the need date with scaling at 3% and at 7% is roughly \$18 million and \$51 million respectively.

### Note: Waitaki Valley – Otago-Southland

Another identified issue that may be significantly impacted by increased peak load in the South Island is the transmission constraints which arise during 'dry' hydro conditions. When this occurs, sending power from the Waitaki Valley and the HVDC link down to the Otago-Southland region becomes necessary. Since this issue is also driven by generation pattern as well, quantifying how peak demand growth will impact this

<sup>25</sup> Indicative project costs in \$2018.

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project is not as straightforward as for the USI project. Although we have not analysed the issue for transmission investment consequences we consider peak demand growth will have an impact and it is worth mentioning.



## Appendix C1 – Peak demand forecast for EDBs impacted by earlier investment: basis, assumptions and checks

The tables below show the 2018 load control estimates we used in Case Studies 1 and 2. We have only included those EDB GXP's whose peak demand contributes to the need for the investments in the case studies. Our modelling estimated peak demand absent EDB response to RCPD by adjusting our underlying peak demand forecasts at (i) 3% uplift, and (ii) 7% uplift.

Under our Transmission Planning Report process we derive a “prudent” peak demand forecast (also known as a P90 forecast). The prudent forecast has a 10 per cent probability of being exceeded during the first seven years of the forecast period and is used to determine the need date for any new investment. The approach is designed to ensure identification of grid issues (needs) with sufficient time for the needs to be resolved.

We establish GXP forecasts, using regression techniques on historical GXP demand, plus feedback from the distribution companies. We combine the top down forecast and GXP forecasts to obtain the GXP contribution to Island and regional peak forecasts. (These contributions are the inputs to regional planning studies.)

As a sanity check we compared the assumed 3% and 7% uplift from losing EDB response to RCPD against ripple control (only) reported by EDBs to the Commerce Commission and published as ‘EDB emerging technology data’ 10 October 2018.<sup>26</sup> Time did not allow us to repeat our analysis using this data. We have instead used it to test the veracity of our assumptions.

**Table C3: Case Study 1. Upper South Island voltage stability - Total contributing load by EDB**

<b>EDB</b>	<b>2018 Peak Demand Forecast (TPR-2017) MW</b>	<b>Load control estimate at 3% MW</b>	<b>Load control estimate at 7% MW</b>	<b>Load control capacity from ripple control, average 2014-2018<sup>26</sup> MW</b>	<b>Load control capacity from ripple control relative to EDB maximum coincident peak demand 2018<sup>26</sup></b>
Alpine	93.4	2.8	6.5	56.6	38.8%
Buller	8.0	0.2	0.6	3.8	34.5%

<sup>26</sup> EDB [emerging technology data – 10 October 2018](#) requested and published by the Commerce Commission.

Electricity Ashburton	76.6	2.3	5.4	15.7	8.7%
MainPower	82.9	2.5	5.8	14.9	13.2%
Marlborough	67.3	2.0	4.7	9.3	12.7%
Network Tasman	126.4	3.8	8.8	14.7	10.6%
Orion	632.9	19.0	44.3	150	24.0%
Westpower	23.7	0.7	1.7	24.0	9.5%
<b>Total</b>	<b>1,111.2</b>	<b>33.3</b>	<b>77.8</b>	<b>269.0</b>	<b>20.2%</b>

Table C4: Case Study 2. Waikato and Upper North Island voltage stability - Total contributing load by EDB

<b>EDB</b>	<b>2018 Peak Demand Forecast (TPR-2017)</b> <b>MW</b>	<b>Load control estimate at 3%</b> <b>MW</b>	<b>Load control estimate at 7%</b> <b>MW</b>	<b>Load control capacity from ripple control, average 2014-2018<sup>27</sup></b> <b>MW</b>	<b>Load control capacity from ripple control relative to EDB's maximum coincident peak demand 2018<sup>27</sup></b>
Counties Power	69.4	2.1	4.9	24.7	21.3%
Northpower	75.0	2.3	5.3	14.7	8.5%
Powerco	446.6	13.4	31.3	189.0	21.2%

<sup>27</sup> EDB [emerging technology data – 10 October 2018](#) requested and published by the Commerce Commission.

The Lines Company	11.7	0.4	0.8	17.2	17.1%
Top Energy	65.8	2.0	4.6	12.0	23.6%
Vector	1624.4	48.7	113.7	x <sup>28</sup>	x%
Waipa	67.1	2.0	4.7	17.5	23.6%
WEL Networks	225.1	6.8	15.8	45.9	16.9%
<b>Total</b>	<b>2,285.1</b>	<b>77.7</b>	<b>181.1</b>	<b>321.0</b>	<b>19.2%</b>

<sup>28</sup> Vector's response reported in the Commerce Commission's database is 'x'.

## Attachment D

### **Impact of removing peak pricing on the electricity market Transpower as the System Operator, October 2018**

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#### **Objective and summary of findings**

The objective of this analysis is to test potential impacts that the transmission peak price known as Regional Coincident Peak Demand (RCPD) charges can have on the wholesale electricity market. Specifically, what are the system impacts when the RCPD price is removed and load control at peak is reduced, with consequential increases to GXP peak demand.

Transmission network peak pricing provides an additional pricing signal to any spot market signals (nodal pricing for energy), including to parties such as electricity distribution businesses (EDBs) that are not necessarily exposed to spot (nodal) energy pricing.

#### **Qualifications**

We caution that we adopted a static analysis for modelling wholesale electricity market impacts. We assumed the reduction in load control by EDBs would not impact on generator offers. We consider this to be a reasonable assumption under fully competitive market circumstances, and conservative for workable competition.

We also only modelled the impact of a change to load control by EDBs, and otherwise held electricity demand constant, i.e. we modelled the impact removal of RCPD would have on controlled load but didn't model the impact change in spot prices would have on demand.

We have not modelled the increase in consumer surplus that results from load control curbing spot prices, and consumers needing to reduce demand less in response to otherwise-higher spot prices.

What this means is that the spot price outcomes from the modelling should be treated as illustrative only, i.e. they indicate the sensitivity of spot market prices to changes in RCPD response and load control, rather than estimates of the spot market price impacts of any removal of peak pricing from the TPM.

More time and resources would be required to fully assess the pricing benefit than was feasible for completion of this report

#### **Summary of findings**

The report confirms EDB load control in response to the TPM peak price signal has positive system impacts. Spot wholesale prices can be very sensitive to even small changes in demand driven by changes (increases or decreases) in load control. Sensitivity is particularly prominent during peak-periods and times when supply is tight in dry-years.

The TPM peak price signal can result in lower demand during spot market peaks than otherwise, which can lower wholesale prices, reduce the need for expensive non-renewable generation, and reduce greenhouse gas emissions. To the extent load control by EDBs curbs spot prices it avoids the need for consumers to reduce demand in response to otherwise-higher spot prices.

## Methodology

Our analysis examined the effect of adding back load controlled by EDBs at peak on wholesale energy prices, generation fleet, asset loadings and market constraints. Appendix D1 explains how the load figures were derived.

We first added load back to the two trading periods (TP) in which we had the highest South Island peak (31 May 2018 TP36) and highest North Island peak (26 June 2018 TP36) in the period September 2017 – August 2018.<sup>29</sup>

Then we added load back to the highest ever recorded peak (15 August 2011, trading period 37) that occurred during the evening on a day that was exceptionally cold nation-wide.

**Table D1: Peaks loads and trading periods as inputs used in analysis**

Peaks		NI Load (MW)	SI Load (MW)	NZ Load (MW)
<b>2018 South Island peak</b>	31 May 2018 TP36(17:30-18:00)	4,221	2,113	6,334
<b>2018 North Island peak</b>	26 June 2018 TP36 (17:30-18:00)	4,411	2,066	6,477
<b>Highest recorded peak</b>	15 August 2011 TP37 (18:00-18:30)	4,694	2,217	6,902

For modelling purposes, we selected nodes which don't have large, single-point load behind them that could dominate other effects (and can be expected to respond to high energy prices). The loads at these nodes are modelled using a standard demand forecast approach.<sup>30</sup> We have used the Scheduling, Pricing, and Dispatch (SPD) tool to create market clearing prices in the alternative scenarios that have been modelled.<sup>31</sup>

### South Island Peak period: 31 May 2018, 17.30 (trading period 36)

We modelled three scenarios.

**Scenario 1: Base case (as occurred).** Energy prices at selected market nodes ranged from \$50/MWh to \$70/MWh. Reserve prices for both islands were less than \$5/MWh.

**Scenario 2: Increase SI load by 182MW (add back EDB-controlled load).** This resulted in the energy price at the various nodes increasing to 6 times of the price of Scenario 1. The reserve price for Fast

<sup>29</sup> The 12-month period 1 September – 31 August is the capacity measurement period grid owner uses to identify peak demand trading periods.

<sup>30</sup> The standard approach doesn't work as well for other nodes where large, single-point loads are required to offer in their load in a similar way to dispatched generation.

<sup>31</sup> The SPD tool is the tool used by the system operator to schedule, price and dispatch generation to meet demand in real time. Generator owners offer their generation quantities for a price, and all offers are stacked in order of price to create a supply curve (often called merit order or price stack).

Instantaneous Reserves (FIR) did not change, but the SI Sustained Instantaneous Reserve (SIR) price increased to 51 times the original price (\$235.64/MWh).

**Scenario 3: Increase NI load by 114MW and SI load by 182MW (NI and SI controlled load).** This resulted in the energy price increasing to 12 times the price of Scenario 1. The price at BEN2201, for example, increased to \$669.58/MWh (compared with \$54.19/MWh in Scenario 1 and \$336.23/MWh in Scenario 2).

The following three tables present figures for energy prices, additional thermal generation / emissions, and additional energy costs; we note the results are indicative of direction only.

**Table D2: Energy Prices at peak loads 31 May 2018 TP36**

Market Node	Scenario 1 \$/MWh	Scenario 2 \$/MWh	Scenario 3 \$/MWh
OTA2201	67.13	403.48	794.40
HAY2201	58.91	366.53	721.48
ISL2201	58.95	371.34	739.49
BEN2201	54.19	336.23	669.58
INV2201	52.66	327.16	651.52

**Table D3: Additional Thermal Generation from Increased Load**

	Scenario 1	Scenario 2	Scenario 3
Thermal (MW)	18% of 6,334MW = 1,140 MW	+ 111.55	+ 206.35
Additional energy (MWh)		56	103
Additional CO2 Emissions <sup>32</sup> (kg)		~ 11,000	~20,000

We estimated the magnitude of total energy cost change from the base case against the scenarios with additional load. The production cost uses the generators' offer price multiplied by their cleared offer. The supply cost was calculated by multiplying the load at each node by the final energy price at each node.

**Table D4: Total Energy Cost (\$) – 31 May 2018 TP36**

	Scenario 1	Scenario 2	Scenario 3
Production Cost \$	14,835	40,639	111,525
Supply Cost \$	395,380	2,485,858	5,003,596

<sup>32</sup> We used [emissions factors](#) information available from Ministry for Environment. Natural gas for stationery combustion is 0.192 kg CO<sub>2</sub>– e per kWh.

## North Island Peak period, 26 June 2018, 17.30 (trading period 36)

We again modelled three scenarios.

Scenario 1: Base case (as occurred). For Scenario 1 the energy prices ranged between \$450/MWh to \$600/MWh with the NI prices being on the higher end. Reserve prices for FIR were less than \$5/MWh for both islands but SIR prices were greater than \$135/MWh for the NI and SI.

Scenario 2: Increase NI load by 114MW (NI controlled load). Under Scenario 2 the energy price increases 51% for both islands.

Scenario 3: Increase NI load by 114MW and SI load by 182MW (NI and SI controlled load). Under Scenario 3 the energy price increased to 11 times the base case price. Fast Instantaneous Reserve (FIR) prices didn't change but Sustained IR prices increased to greater than 40 times the base case price.

The following three tables present figures for energy prices, additional thermal generation / emissions, and additional energy costs; we note the results are indicative of direction only

**Table D5: Energy Prices at peak load 26 June 2018, 17:30**

Market Node	Scenario 1 \$/MWh	Scenario 2 \$/MWh	Scenario 3 \$/MWh
OTA2201	590.09	889.27	6,682.14
HAY2201	509.24	767.47	5,863.37
ISL2201	508.71	766.68	5,918.37
BEN2201	468.44	705.98	5,364.92
INV2201	452.97	682.68	5,216.38

As in the May 2018 South Island scenarios we modelled, the contribution of thermal generation in terms of MW increased as system load is increased. Wind generation contributed 240MW in the trading period analysed.

**Table D6: Additional Thermal Generation from Increased Load (Compared to Scenario 1)**

	Scenario 1	Scenario 2	Scenario 3
<b>Thermal (MW)</b>	19% of 6477 MW = 1,230	116.03	179.81
<b>Additional energy (MWh)</b>		58	90
<b>Additional CO2 Emissions<sup>33</sup> (kg)</b>		~ 11,000	~17,000

<sup>33</sup> Used [emissions factors](#) information available from Ministry for Environment. Natural gas for stationery combustion is 0.192 kg CO<sub>2</sub>-e per kWh

The table below shows the magnitude of total energy cost change from the base case corresponding to the scenarios with additional load. The supply cost was calculated by multiplying the load at each node by the final energy price at each node. The production cost uses the generators offer price multiplied by their cleared offer.

**Table D7: Total Energy Cost (\$) – 26 June 2018, 17:30**

	<b>Scenario 1</b>	<b>Scenario 2</b>	<b>Scenario 3</b>
<b>Production Cost \$</b>	69,666	151,209	378,305
<b>Supply Cost \$</b>	3,618,685	5,555,546	43,157,809

Note the large increase in total energy cost following increases in load. As the base case already had high prices, additional load aggravated the situation.

### Highest recorded period, 15 August 2011, 18:00 (trading period 37)

We investigated if the grid could meet peak demand, using the highest recorded peak (15 August 2011 TP37) and adding back controlled load. We used the offered grid, generation and reserves for 26 June 2018 TP36.

We found the grid could meet peak demand only if a Stratford Peaker was made available (both Stratford peakers were on planned outages on 26 June 2018). However, the required reserves were not able to be covered. The SPD solution yielded infeasible results, which would have been forecast to participants ahead of time.

### Response to forecast infeasibilities to avoid load shedding

To avoid load-shedding wherever possible, any forecast infeasible SPD solutions initiate a response from the system operator.

The relative prices associated with deficits of CE reserves (\$100,000/MW) and energy (\$500,000/MWH) combined with the market's co-optimisation of energy and reserves means reserve deficits will occur before energy deficits. This industry agreed approach avoids the need for load shedding until there is an actual shortage of generation to meet load. The approach does however expose the power system to increased risk of more severe outcomes should a tripping occur. The lack of full reserves increases the likelihood of an AUFLS trip occurring for an event which would not normally activate AUFLS.

Reserve deficits are not permitted to occur for the system risks that AUFLS is scheduled to cover,<sup>34</sup> since doing so would expose the power system to the risk of cascade failure. This situation is avoided by pricing this type of reserve deficit at \$850,000/MW. A value higher than some energy deficits e.g. it is cheaper for the market optimisation to have an energy deficit instead.

<sup>34</sup> Extended Contingent Events (ECE). ECE are larger, less likely risks such as the tripping of both poles of the HVDC simultaneously.



### 36 Hours ahead: Forecast schedules and automated warning notices

Forecast schedules and automated warning notices are published from 36hrs ahead of real-time. If energy and reserve needs cannot be met from the offered resources (energy, reserve, and transmission capacity) participants are made aware of this via the 'prices' published. These aren't prices as such but rather 'flags' which indicate that a deficit is forecast. These 'prices' are set to levels well above market prices. For example, a contingent event such as a large generator or single HVDC pole tripping creates reserve deficits priced at \$100,000/MW and energy deficits priced at \$500,000/MWh. These very high values ensure the market system uses all physical assets prior to deficits occurring in real time.

The scheduling process also creates notices which warn participants of any energy or capacity issues should the largest single source of generation trip off. The analysis and notice happen automatically after completing the forecast schedules.

### Before Gate Closure:<sup>35</sup> Further warning notices

The next step is the real-time operation staff issuing further warning notices to highlight concerns with the power system's ability to maintain secure operations. Warning notices are an escalation of the automated warning notices and are issued in sufficient time for market participants to freely alter their generation and reserve offers. All warning notices request participants undertake the actions which would alleviate the forecast shortfall, including increasing generation and reserve offers and decreasing load.

### After Gate Closure: Grid Emergency declared

If forecast deficits continue into the gate-closure period, then a Grid Emergency would be declared via a Grid Emergency Notice (GEN). A GEN would request increased offers of generation and reserves be made available and request demand reduction too. The GEN allows re-offer within the gate-closure period. The GEN also details the emergency steps which the system operator may take to manage the power system. At this point the only lever left is load-shedding.

### Real-time: Demand allocation and load control

If an energy deficit does exist in real-time and system frequency is, or will be, affected then the only option left to the system operator is to shed load. The quantity of the imbalance is allocated to the distribution companies in the affected area pro-rata and communicated via a Demand Allocation Notice (DAN). In practice the load control instructions manifest as a maximum limit rather than a 'delta'. Load control instructions are rescinded in a controlled manner once system conditions allow.

Through the multiple signalling channels, prices and notices, we would also expect voluntary load shedding from distribution companies and price sensitive industrial load to have occurred.

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<sup>35</sup> Gate closure is 1 hour ahead of real-time. After gate closure offers cannot be altered without a bona-fide reason.

## Appendix D1: Derivation of load control figures used in analysis

In July 2016 the Grid Owner commissioned Scientia Consulting<sup>36</sup> to study the effect that removing load control and distributed generation would have on load increases for each of the four pricing regions. For that study, the Grid Owner elicited and received voluntary load control figures from many (but not all) EDBs. Those informal numbers are the basis for the aggregate (island level) figures for load control. We did not allow for any load control by EDBs that did not provide information to us in 2016.

During the course of this System Operator study, EDBs were required by the Commerce Commission to formally report a range of information and data relating to emerging technologies within their networks. The Commission published this data set on 10 October 2018.<sup>37</sup> We have used it to check the credibility of the aggregate load figures derived from Grid Owner's informal figures.

We consider the assumptions used to model the potential impact of EDB load control on peak demand to be conservative (modelled load control more likely to be too low than too high).

**Table D8: Aggregate EDB Load control figures**

All in MW	Subset of EDBs who provided load control information to Transpower in 2016			All EDBs	
	2016 Transpower information request		Island total (@ 0.7 effectiveness)	Commission database <sup>38</sup>	
	Maximum load control reported by EDBs in 2016	Apply effectiveness factor @ 0.7 <sup>38</sup>		Island total (@ 0.7 effectiveness)	Island total
Upper North Island	90	63	114	294	486
Lower North Island	73	51			
Upper South Island	210	147	182	219	332
Lower South Island	50	35			

<sup>36</sup> Scientia consulting, [Embedded generation and gross demand analysis](#), July 2016

<sup>37</sup> EDB [emerging technology data – 10 October 2018](#) requested and published by the Commerce Commission.

<sup>38</sup> An assumption relating to availability for RCPD response

## Appendix 2: Responses to the consultation questions

Consultation question	Transpower response
<p>Q1 Do you agree that distributors need to reform their prices? What is the reason for your answer?</p>	<p>We support the initiatives being undertaken to review distribution prices. The issues around the impact of technological development are well understood and we don't think they are contentious.</p> <p>We agree that distribution pricing could more accurately reflect costs. This will become increasingly important as the economics of new technologies improve, including electric vehicles, solar PV and batteries. It is recognised that there is potential for EVs, under current price structures, to magnify demand in evening peak hours and potentially require significant additional network investment.</p> <p>There are also equity concerns, with higher-income households able to reduce their distribution charges (e.g., through solar PV) without reducing the cost of their connection to the distributor – potentially leaving lower-income consumers to pick up the bill.</p>
<p>Q2 How important and urgent are the issues identified by the Authority?</p>	<p>We support the view that it will be easier to implement pricing reform before consumers make substantial investments, based on the benefits and incentives created by existing pricing.</p>
<p>Q3 Do you agree with the proposed Distribution Pricing Principles?</p>	<p>Refer to the body of our submission which reproduces an extract of our submission to the Electricity Price Review and references principles being applied to network pricing reform by OFGEM.</p>
<p>Q4 What if any changes would you recommend are made to the proposed Distribution Pricing Principles, and why?</p>	<p>In summary, we support the Authority referring to comparable and leading international regulatory reform processes for pricing change and Transpower would like to see:</p> <ul style="list-style-type: none"> <li>• A focus on simplifying network pricing, both transmission and distribution;</li> <li>• Retention of the focus on signalling the cost of future investment;</li> <li>• Cross-sector consistency; and</li> <li>• A joined-up approach to distribution and transmission pricing.</li> </ul> <p>We recommend:</p> <p>(i) any changes to the distribution pricing principles is sensitive to alignment with the principles for the Transmission Pricing Methodology (TPM), the importance of signalling peak network usage, and the way that new technology will change the role and consumption behaviour of consumers.</p> <p>(ii) pricing reform for New Zealand is viewed with an implementation lens as well as an efficiency lens, and</p>

Consultation question	Transpower response
	<p>follows a consultative process focussed on achieving stakeholder and consumer acceptance.</p> <p>(iii) retaining the principle “Prices are to signal the economic costs of service provision by: ... signalling, to the extent practicable, the impact of additional usage on future investment costs” because of its vital role in managing costs to consumers into the future. To do so would be consistent with previous views published by the Authority.</p> <p>(iv) a consistent, cross-sector approach to network pricing, where differences in approach reflect genuine industry-specific factors, and a coherent and joined up approach to electricity network pricing across transmission and distribution.</p>
Q5 What if any changes would you propose to the star-ratings to better reflect the relative efficiency of distribution prices?	No comment.
Q6 How long do you think distributors would reasonably need to introduce the different price structures discussed above?	Successful price reform will hinge on its acceptance by consumers. We consider the industry and regulators should work together to deliver near-term distribution pricing reform by focusing on simple, pragmatic, directionally-efficient and quick to implement new tariffs targeted at known current problems.
Q7 Can you illustrate how and to what extent the LFC regulation hinders price reform?	Transpower is not directly impacted by the LFC Regulations. We understand from both distributors and retailers the LFC Regulations are an impediment to the introduction of more innovative pricing arrangements.
Q8 How accurately has the Authority categorised distributor revenues and costs? How could this be done more accurately?	No comment.
Q9 What if any would be better indicators of the efficiency of distribution prices, or the ambition of and progress being made by distributors on their price reforms?	No comment.
Q10 What assistance could the Authority (or other stakeholders) offer distributors in order to speed up the reform process, or help to remove or reduce barriers to distribution price reform?	<p>There are some issues that overlap between Transpower and EDBs. This includes, for example:</p> <ul style="list-style-type: none"> <li>• how to set peak-usage prices (including reflecting transmission peak prices in distribution tariffs), and</li> <li>• potential approaches to LRMC pricing.</li> </ul> <p>We would be happy to assist in any way the Authority or EDBs would consider helpful. We note we have provided a white-</p>

Consultation question	Transpower response
	<p data-bbox="587 237 1340 331">paper, by Sapere, on issues for adopting LRMCM pricing, which should be useful for both distribution and transmission pricing reform.<sup>1</sup></p> <p data-bbox="587 342 1340 436">We consider an Expert Advisory Panel, made up of well-respected, international experts, could assist with the network (distribution and transmission) pricing issues.</p>

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<sup>1</sup> We commissioned Dr Stephen Batstone of Sapere Research Group to research and consider practical design aspects of an LRMCM charge for New Zealand's TPM. The literature search analysis has been peer reviewed by Dr E Grant Read (Consultant and Adjunct Professor, University of Canterbury): [Sapere, Issues to consider in designing an LRMCM pricing regime, August 2017.](#)

This work was commissioned as part of the planning and preparatory work we had commenced for development of a new TPM. At the time we had expected the Authority would make a decision to replace the existing TPM Guidelines by April 2017. We expected the new Guideline would allow for peak pricing signals in the form of long-run marginal cost (LRMCM) charging and we wanted to better understand how LRMCM pricing might work in practice.