A Guidance Paper for Electricity Distributors on new pricing options

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Prepared by the

Electricity Networks Association

Contents

Foreword

The future of electricity hasn't been this exciting for decades.

New technologies are ushering in innovative ways for consumers to use, generate, store, and manage the electrons flitting through their household's wires. This wave of change is gathering momentum in New Zealand. But looking overseas, it's clear the way that Kiwis interact with electricity will be turned on its head in the next quarter of a century.

All this upheaval creates opportunities for the electricity distribution industry. While the industry is already modernising how it manages the 150,000 km of cables and wires to produce a safe and reliable electricity service, the way that distribution services are priced has not kept similar pace.

Improving how we price to consumers to ensure that we provide them with choice about how they pay for services, opportunities to take advantage of new technology, and ways to save money, is a key goal for members of the Electricity Networks Association.

In the same way that consumers purchase a data limit on their broadband service and pay accordingly, a consumer might select a level of electricity capacity that suits their needs. Or a consumer might choose a pricing option based on the time of day that they require the network. If they know electricity costs less during times when the network is used less, such as overnight, they could run some appliances or recharge their cars overnight.

We're examining different ways to price our services so consumers have incentives to use electricity in ways that will save them money immediately and save money for the whole community in the longer term.

These guidelines set out guidance for ENA member companies on new types of pricing. It examines the changing use of electricity and suggests new ways of pricing for network services.

Changes must be supported by consumers, and other important stakeholders such as electricity retailers. That's why discussions on pricing reform need to focus on the end consumer and encourage consumers' active participation around new pricing options.

I hope these guidelines are a useful resource for pricing practitioners across the country who can be agents for change in unlocking the value of new energy technology by providing incentives and choices for consumers.

Ken Sutherland

Chair

Electricity Networks Association

The structure of this guidance paper

This guidance paper has an Executive Summary and four parts.

Executive Summary

The Executive Summary covers in brief:

- the need for pricing reform
- the main pricing structure options
- how we evaluated the options
- issues regarding implementation of new pricing.

Part 1 – The need for change

Part 1 covers the need for change in more detail. It sets out the structure of existing pricing and why the industry must lead pricing changes. It describes what future pricing could look like, the criteria it must meet, and a path to change.

Part 2 – Consultation with all stakeholders – consumers, retailers, and distributors

Part 2 proposes how to consult with the groups who will be affected by pricing change.

Part 3 – Options for pricing change

Part 3 describes and evaluates five key types of pricing in detail:

- time-of-use consumption
- customer peak demand
- network peak demand
- installed capacity
- booked (or “nominated”) capacity.

It describes our criteria and how we assessed the above pricing components (which can be used either individually or in a combination) with the aim of identifying pricing that is efficient, fair and effective in the long term.

Part 4 – Implementation

Part 4 describes how distributors and stakeholders could implement new pricing. It explains ways to transition consumers to more service-based pricing that better reflects costs.

Executive Summary

Purpose

The purpose of these guidelines is to provide guidance to electricity distribution pricing practitioners and interested stakeholders on matters relating to cost reflective pricing structures. It incorporates feedback received from stakeholders during the consultation process.

The paper encourages distributors to consult with consumers and their communities to understand consumer preferences in designing alternative pricing structures. Ultimately, any change in pricing structures will need to be informed by consumer preferences.

This work fits into a wider sector interest in efficient network pricing and the impact of technology and market changes on the broader energy sector. It is a stage in an ongoing process of change.

Why we're exploring new pricing options

Current pricing structures were developed under different market conditions. For well over a century, the traditional electricity supply chain was centrally managed with one-way electricity delivered from large-scale generation through to consumers via a transmission and distribution network. The recent advent of technological change has the potential to have a significant impact on the way in which the electricity industry operates. The ability of consumers to impact both network flows and system maximum demands through energy storage, new energy uses and energy management, means that consumers are now becoming the central focus point in a transformed supply chain.

Because they are more reflective of underlying network costs, the new pricing structures discussed in these guidelines can facilitate consumer choice in the use of electricity and new technologies. These pricing structures can provide incentives to drive the most optimal use of, and investment in, distribution networks, with the potential to save all consumers around $200 per year in the long term[1].

The potential benefits of new pricing structures

- **Incentives to use energy smarter** – it's not just about ***how much*** energy is used, but also ***when*** it is used
- **Consumer choice** – facilitating options around use of existing and new technologies
- **Lower prices** – in the long term, than what would otherwise occur
- **Sustainable distribution networks** – to support the new energy future

[1] Based on an increase of 10% in an average residential retail electricity bill of $2,000 per annum. See NZIER, September 2015, *Effects of distribution charges on household investment in solar*, p. i

Options for changing prices

We identified five network pricing types that could be used either on their own or in combination, to meet consumer and industry needs in the future:

- time-of-use consumption
- installed capacity
- booked (or "nominated") capacity
- customer peak demand
- network peak demand.

These pricing types were selected on the preliminary assessment that they had the greatest potential to reflect costs, be stable and durable, and could be operationalised in the short to medium-term. We have proposed a template option for each pricing type, informed by consultation with consumer groups and other stakeholders. We have suggested templates of price structures and definitions to encourage alignment across distributors on how each pricing type is designed.

We have not recommended specific types of pricing over others: distributors will face different circumstances and will need to consult with consumers on their own networks to understand their preferences. We do however consider that the ENA is well placed to assist members to further develop a consistent set of pricing options and to consider optimal combinations of the pricing types.

Fixed daily prices are not discussed in detail in these guidelines because they are already in place and the Low Fixed Charge (LFC) regulations limit the fixed network price for most residential consumers to 15 cents a day.[2] Fixed prices can be used in combination with other pricing types discussed in these guidelines.

Figure 1: Cost-reflective network pricing options

[2] It is noted that an increased fixed price would be one means to align prices more closely with some underlying costs.

Priority should be given to selecting from these five pricing types for a first phase of pricing change. We see these as the foundation steps for future market developments and, in the short term, expect these to be refined as more information and learnings from consumer engagement are collected. We anticipate that a second phase of pricing change may evolve, providing locational and dynamic pricing in response to new market developments.

How we assessed the types of pricing

We assessed the pricing types by scoring each against a set of criteria that demonstrates the extent they will achieve desired outcomes. The overarching criteria used were that pricing should be:

- **Efficient:** Pricing types were assessed according to whether they promote economic efficiency by (a) signalling future network costs; (b) enabling recovery of fixed and sunk costs in a non-distortionary way; (c) being equitable by ensuring that price fairly reflects the cost incurred as a result of individual actions, with consumers that place the same demands on the network paying similar charges; and (d) efficiently signalling the costs of providing network services relative to the cost of other energy technologies.
- **Actionable and simple:** This was looked at from two different perspectives: (a) whether consumers can understand and choose to respond to price signals; and (b) whether the pricing type can be implemented with manageable resource costs.
- **Durable and flexible:** This was approached by considering whether the pricing structure has the flexibility to respond to changing external circumstances such as technology.
- **Stable and predictable:** consider if the pricing structure enables accurate financial planning by consumers and provides stability over time that minimises bill fluctuation.
- **Supports retail competition:** The pricing structure can be applied across different distributors consistently with limited distortion to retail competition.

Section 9.2 of this report compares the five pricing types against detailed evaluation criteria associated with these key pricing features. Distributors will have to consider the trade-offs involved with different types of pricing, especially with the efficiency of each pricing type relative to its impact on consumers in their own network, as well as local implementation considerations.

Selecting pricing types

When developing a view of a suitable pricing type, distributors are encouraged to consider carefully the circumstances of their network, including network capacity utilisation. Distributors can then engage with consumers on their network to better appreciate their preferences and level of consumer understanding in a process of refinement that delivers successful change, supporting choice.

Introducing half hour-based pricing

Smart metering supports implementation of new pricing structures that rely on half-hourly data. The extent of penetration of smart meters will affect the pace of any transition. Although nearly 80% of New Zealand residents have smart metering, there is a wide variation in penetration across distributors. Consideration will need to be given to data access and quality, and protocols established for the effective exchange and security of this data.

Initial feedback from electricity retailers and ENA members suggests that the industry's billing and data management systems are generally not capable of the half hour (HH) billing for residential and small business connections that is required for change to some of these types of pricing. Distributors, retailers, and meter service providers may need to invest further in metering infrastructure and systems to implement HH based pricing. The industry will need to coordinate to confirm billing protocols and develop methodologies for HH billing estimation. As much as possible it will be important for distributors to align cost reflective pricing structures, especially in a local sense where coalitions of neighbouring distributors could share learnings and share the implementation load, including engagement and communications strategy and tasks.

Acceptance by consumers

Consumer understanding and acceptance of change are key goals of an engagement process. Having developed a preliminary view of the design features for a number of new pricing options, distributors are encouraged to seek the views and input of their consumers, their wider community, and other stakeholders utilising focus groups, online surveys, one-on-one meetings, and workshops. Distributors should reflect on the learnings of this engagement to narrow preferred future pricing options, modifying the design of those options if necessary and re-engaging with consumers and the community in an iterative process that ensures that the new pricing options have been rigorously reviewed. The ENA has resources, and is willing to assist member companies, to develop and work through this important engagement process.

Transition to new network pricing:

- Change can be phased in
- A purely opt-in approach may not achieve overall objectives
- Immediate implementation for all consumers may lead to confusion and complexities
- A clear pathway to implementation is important, with transparency on timeframes
- A series of smooth price changes over time
- Consumer education and communication is vital, with consistency and coordination across industry
- Effects on vulnerable consumers need to be managed, including by coordinating with relevant agencies and other parts of industry.

Next steps

At the time of completing this guidance paper, the ENA is actively planning the next work streams to support members as they look to implement pricing reform. The DPWG terms of reference is being modernised and three work streams are being considered:

- **A joint technical group** – to consider, with retailers, the detailed issues that will affect implementation
- **A workgroup -** to look at what cost reflective pricing means in practice and the role of pricing
- **A workstream** – to support members with stakeholder engagement and communications.

You are encouraged to approach the ENA to seek advice or support when considering pricing reform. To set up a meeting or make enquiries about anything in this guidance paper, email the ENA: info@electricity.org.nz

Part 1

The need for change

1 Introduction

The purpose of these guidelines

> **What is the ENA and the DPWG?**
>
> The Electricity Networks Association (ENA) represents the 29 distributors operating in New Zealand.
>
> The Distribution Pricing Working Group (DPWG) was established by the ENA in 2014 to lead, assist and coordinate distributor efforts to establish more durable and efficient pricing arrangements for network consumers.
>
> The DPWG takes a forward-looking approach to evaluating the pricing options available to distributors, providing guidance to help distributors better align their pricing. The DPWG encourages a coordinated approach to developing future pricing structures with input from all distributors.
>
> Effective engagement with consumers, retailers, and regulators is considered crucial to developing a reliable view of the future direction of distribution pricing. This is achieved through surveys, meetings, and workshops.

These guidelines discuss the development of new pricing structures for residential and small business consumers[3]. It was prepared by the DPWG and contains practical guidance on many aspects of pricing reform and implementation, to facilitate alignment across the membership.

This work fits with the topic of efficient network pricing and the impact of technology and market changes on the broader energy sector. We see it as a stage in an ongoing process of change.

Process to develop future pricing

Changes to technology and the way in which electricity is generated and used have prompted both the industry and regulators to question whether existing pricing arrangements are stable and efficient in the long-term.

The ENA released a discussion paper on distribution pricing in May 2015. The Electricity Authority (EA) also examined the implications of evolving technologies, and sought feedback on how distribution pricing could work with these changes, in a consultation paper published in November 2015. Building on the work carried out by the ENA and the EA, the ENA released a further consultation paper in November 2016. That paper took the further step of examining several key types of pricing in detail and considering how they might be implemented. This guidance paper incorporates further findings from relevant literature, as well as feedback received from retailers and consumers in response to the consultation paper. It also contains pricing templates aimed at facilitating alignment between distributors.

A robust process for developing new pricing structures will involve several iterations of consultation by the ENA and distributors and working closely with retailers regarding implementation. Although this takes time, it is important for all electricity consumers that we get our pricing right.

[3] This is the "general" consumer group identified in the ENA's *Pricing guidelines for electricity distributors*.

2 What should future distribution network pricing look like?

To be effective in the long-term future pricing of distribution services should be:

- efficient;
- actionable and simple;
- durable and flexible;
- stable and predictable; and
- support retail competition.

Efficient: Pricing structures that maximise economic efficiency will be cost-reflective and aligned with the services provided. In this guidance paper we assess whether a pricing type promotes economic efficiency by considering whether it: (a) signals future network capacity investment costs; (b) enables recovery of residual fixed and sunk costs in the least distortionary manner; (c) is equitable through ensuring that price fairly reflects the cost incurred as a result of individual consumer actions with consumers that place the same demands on the network paying similar charges; and (d) efficiently signals the costs of providing network services relative to the cost of other energy technologies.

Actionable and simple: To be effective in practice, pricing structures must provide price signals that consumers can understand and choose to respond to. In addition, implementation and on-going costs and resource requirements must be manageable. Pricing structures that retailers can transparently pass-through to consumers, should they wish to do so, are more likely to effectively promote efficiency in practice.

Durable and flexible: It is important that pricing structures be effective in the long term – independent of market, technology, and policy changes. Ideally, pricing structures will have the flexibility to respond to changing external circumstances (e.g technology, consumer profiles).

Stable and predictable: To be a workable pricing solution, the pricing structure should enable accurate financial

Network prices: what they are and where they sit in the energy supply chain

Electricity consumers generally buy their electricity from electricity retailers. Retailers purchase energy from the wholesale market and pay network charges to distributors and energy charges to generators.

Network prices

Network prices include two components relating to the costs of: (1) the distribution network; and (2) the national transmission grid. Charges from Transpower to distributors for the use of the national grid are passed to retailers in the form of a combined network charge.

Local network distribution:

Electricity distributors are responsible for distributing electricity from the transmission network grid exit points (GXPs) through local distribution low voltage networks to electricity consumers. Increasingly, distributors are also re-distributing electricity generated by consumers on their network.

National transmission grid: Transpower owns and operates the high voltage transmission system (the national grid). The grid is used to transport electricity from generators to GXPs in the local distribution networks.

Energy generation:

In New Zealand, generation fuel is mainly renewable - hydro, wind, solar, geothermal, but also some gas and coal. Generators compete in the wholesale energy market where retailers buy electricity.

planning by consumers and provide stability over time, avoiding volatility. This is particularly important in respect of the most vulnerable consumers.

Support retail competition: It is important that the price structure can be applied across different distributors consistently, with limited distortion to retail competition.

The practical application of these features translates into the following three outcomes for stakeholders:

Figure 2: Outcomes for stakeholders

For consumers: fair pricing that supports choice

For retailers: fit-for-purpose pricing

For networks: pricing that reflects costs and is durable

Source: ENA

Consumer choice in this context refers to the ability for consumers to choose if, and when, to use grid-supplied electricity, as well as the amount of capacity and electricity consumption they require.

The optimal pricing method may vary by distribution network because of the unique characteristics of each distributor's environment. For example, consumers will vary across regions as will geography, climate, network design and congestion levels.

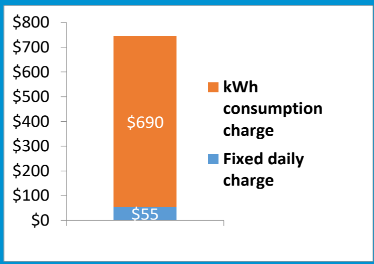
Clearly there are priority trade-offs between pricing that is efficient (and cost-reflective) but is still simple, practical, socially responsible, and understandable. It is important to clearly identify and assess trade-offs of this type. This tradeoff is discussed in more detail in section 9.2.

Illustrative example of existing network pricing

An average residential consumer uses 7265 kWh per annum. Average network pricing for this consumer:

- Network fixed daily price: 15 cents
- Network price per kWh: 9.5c

The total annual amount charged to the retailer by the distribution network for this consumer would be $745: $55 in daily fixed charges plus $690 in consumption charges.



Source: *ENA analysis using data from Ministry of Business, Innovation and Employment (MBIE), Sales Based Electricity Costs, May 2016.*

2.1 The case for change in distribution pricing

The electricity industry is changing as consumers embrace new technologies and rethink how they source and use electricity. Electricity networks are integral to these changes, but they must also continue to provide safe and secure electricity to everyone.

Electricity prices are one of the mechanisms that will enable the changes to evolve efficiently and without distortion. Prices that do not reflect the costs incurred by distributors will distort investment and consumption decisions, wasting resources. This waste is not in the long-term interests of New Zealand electricity consumers.

The existing structure of network prices

Network charges make up around one third of retail bills. They are made up of the transmission grid and distribution network charges. Mostly they relate to investing in and maintaining the assets needed to deliver electricity.

Network prices for most residential consumers are applied to the amount of energy used (consumed energy is measured in kilowatt hours - kWh) plus a "daily price". For many consumers, the network daily price can be limited by regulations to 15c per day.

Service-based pricing

"Service-based pricing could help all consumers benefit from advances in technology.
It means consumers could decide what level of service they want and what actions they could take to reduce the costs they cause to the network.

It could also give consumers far more choice and control and create a pricing structure that is more durable and achieves long-term benefits for all consumers."

Refer: Signposting the Future – Implications of evolving technology for the pricing of New Zealand's distribution. Electricity Authority (2015)

Additional types of network pricing offered by some distributors include:

- **Hot-water saver rates:** Several distributors offer these. They reward consumers with a discounted price if the distributor can switch off hot water heating during periods of high demand on the distribution and/or transmission networks.
- **Day/night pricing:** Provides consumers with a discounted night rate (for example, 11pm to 7am), with a higher rate at other times.
- **Advanced meter pricing:** Some distributors have already introduced more sophisticated pricing using advanced metering such as time-of-use consumption pricing. However, this is generally in the early stages of uptake.

Traditional residential pricing is not service-based and does not reflect costs

The basic pricing structure faced by most residential consumers of a fixed daily price plus an energy price per kWh does not accurately represent the services provided by distributors, nor the costs of providing them.

Rather than providing energy (which is purchased and provided by retailers), distributors provide the distribution network to transport that energy. Because of this, much of distributors' costs do not relate to the amount of energy consumed.

Networks are built and operated to both:

- provide access to the network at a given level of capacity
- make sure that consumers' demand for electricity at peak times can be met.

Peak demand is measured in kilowatts – (kW). The total amount of energy used (measured in kWh) is important for consumers, but this is not what drives costs in the network.

The EA identified the following three services that distributors provide:

1. Transporting electricity to a consumer's premises at a level of quality and reliability
2. Keeping a certain amount of distribution network capacity available for the consumer to use at the "flick of a switch" whenever they want
3. Acting on a consumer's behalf to manage the consumer's use of the distribution network.[4]

A further service identified by the EA for which there is a growing demand as residential consumers install their own generation is: "Transporting electricity from a consumer's premises to neighbours, people living in the area and possibly the wider network." This service is not examined in the current paper because the regulation of the applicable pricing principles is under review by the EA.[5]

A key reason for the existing pricing structure is that legacy metering technology only measured total energy used (kWh). Other pricing that better reflected the services provided or the costs incurred was not possible to implement. There has also been significant uncertainty surrounding which pricing approaches were consistent with regulation.

Pricing that reflects costs will result in lower prices in the long term

Prices need to reflect costs for several reasons. For consumers, prices that reflect cost are important in the short term because they remove cross-subsidies between consumers, meaning everyone pays a fair price both for having the network available and for using it. In the longer term, consumers will see lower prices if they use electricity outside of peak hours, because this reduces future investment in network capacity.

For distributors, prices that reflect costs provide clear signals from the market about how much electricity is needed at different times of the day. Distributors can plan and operate their network more efficiently. The changes in pricing structures, and adoption by networks, are not aimed at increasing prices or revenues; they are likely to lead to lower prices in the future than what would otherwise occur.

Long-term price stability will lead to more efficient investment

Prices for electricity need to be stable in the long term to provide consumers with the right signals about their investment and consumption decisions. For example, the increasing number of consumers generating power for themselves distorts the way that current pricing reflects distributors' investments in the networks. Use of generation by consumers continues to grow, and the price of storage batteries is falling, both of which could result in lower demand for network services and hence less investment in networks for peak demands.

The features of existing pricing are resulting in undesirable outcomes and inefficient investment by both consumers and networks.

[4] Electricity Authority (3 November 2015) *Implications of evolving technologies for pricing of distribution services - Consultation Paper*, page D.

[5] Electricity Authority (17 May 2016), *Review of distributed generation pricing principles*.

2.2 Technology is changing the energy sector

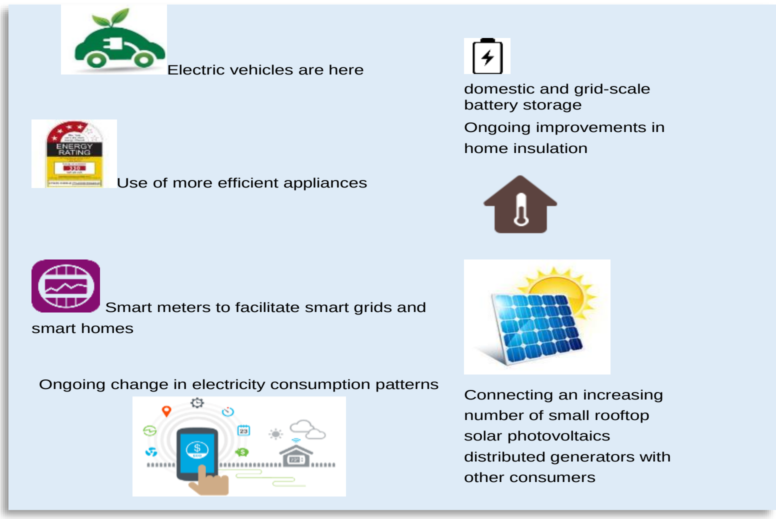
Distribution networks have priced delivery services based on energy consumption which reflects the traditional supply chain pricing from generation to load measured in kWhs of energy. This also partly reflects metering technology, which, until recently, was limited to manual reading of total energy consumption over a month or two (again in kWh). Legacy meters could not record how much each consumer used during the peak, except for the largest of connections that had time-of-use (TOU) meters.

However, networks are not configured based on the amount of energy consumed, but are built to accommodate the peak energy demands of consumers at any one point in time (this is often the highest in the early evening).

The technology situation has changed and the pace of change is increasing, making more cost reflective forms of network pricing possible and necessary. Examples of change in the electricity sector include:

- Consumers have increasing choice. More than 30 retailers offer supply choices
- Increasing numbers of individual residences and communities have access to technology that gives them local generation
- The way in which consumers use electricity is evolving
- Time-of-use meters are being rolled out to small and medium consumers

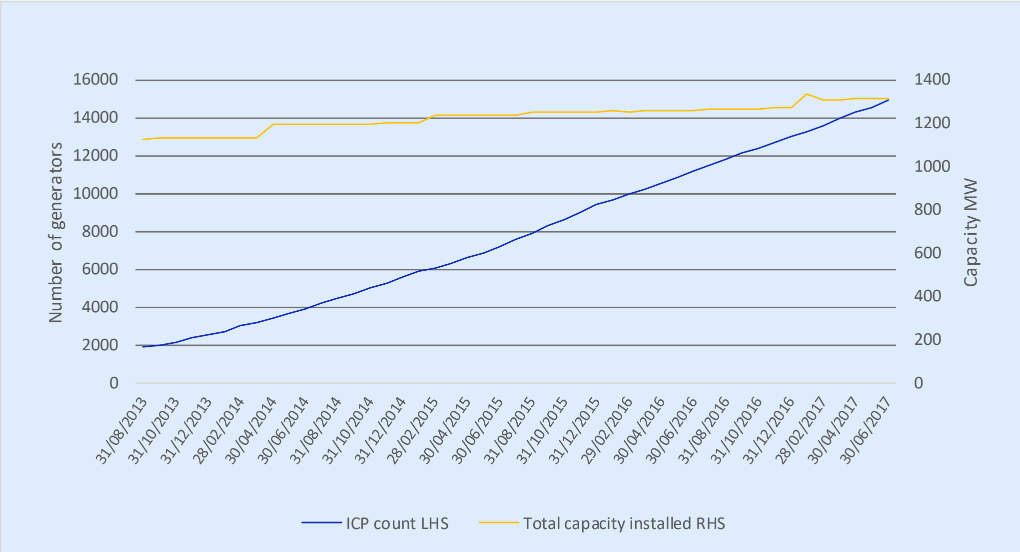
Figure 3: Examples of technology change that affects distributors and consumers



Generation has come closer to consumers

New Zealand still has large-scale renewable generation that is grid connected. However, some consumers are starting to become generators themselves. Across New Zealand, more than 14,000 consumer sites (as at July 2017) now generate electricity either for their own use or to sell into the distribution network. Three years ago, there were just 2,000 sites. Most of the current sites – 13,500 – are residential sites with solar panels. Three years ago, the figure was 1,000 sites.

Figure 4: Local generation in New Zealand (to 30 June 2017)

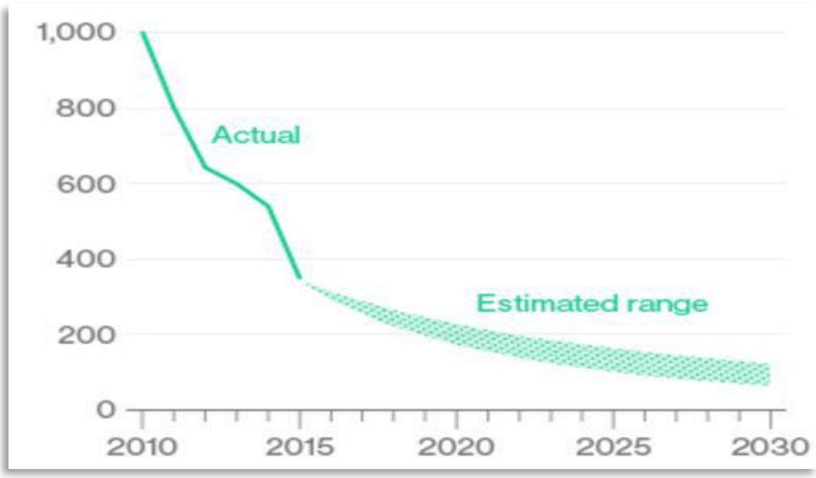


Source: ENA from Electricity Authority data

The way power pricing is structured has quickly become more important because of changes in technologies that are underway, and the way that consumers use energy. Consumers can now generate their own electricity locally, use smart appliances and sell surplus power.

For consumers, the future looks like it will continue to offer wider choice and lower-cost technology. The cost of technology – solar, batteries, and electric cars – is predicted to decline steeply, according to a 2016 report from economic consultancy Concept Consulting.[6]

Figure 5: Historical and projected fall in battery costs (US$/kWh of storage)

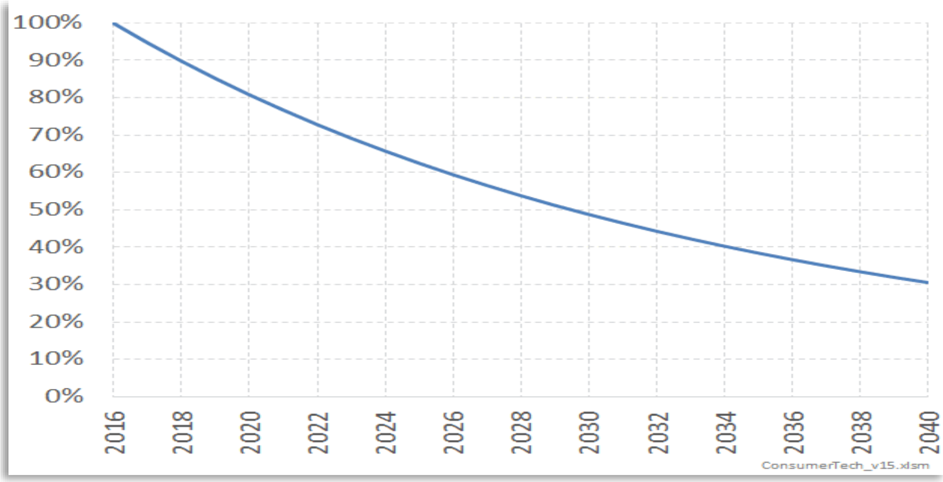


Source: Concept Consulting 2016 report on economics of new technology

[6] Concept Consulting "New Technologies Study: Part 2 – Economic impacts" June 2016.

Batteries offer some of the largest projected cost reductions (see Figure 5 above), while the cost of solar PV systems will follow a similar trajectory (see Figure 6).

Figure 6: Projected (real) rate of decline of costs of installed rooftop solar PV systems



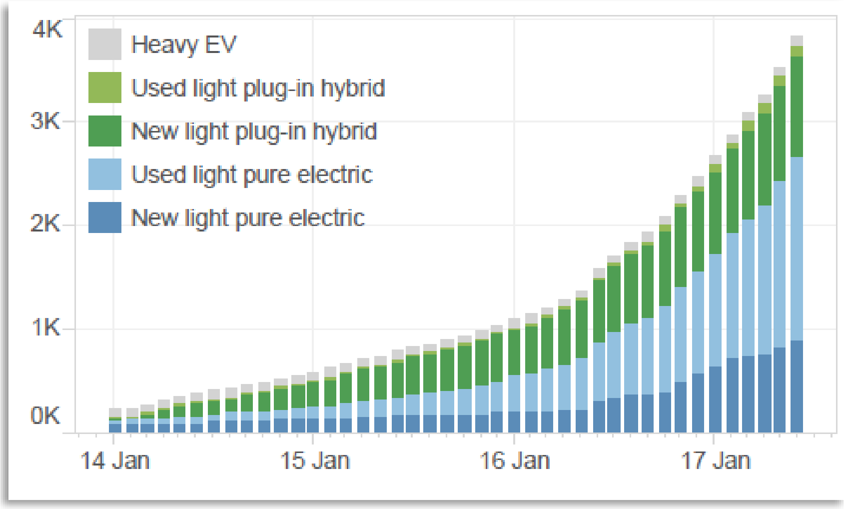
Source: ENA from Concept Consulting

Electric vechicle interest is gaining momentum

Electric vehicle (EV) uptake is currently in its infancy but is steadily increasing (see Figure 7). With new models being launched by a range of car manufacturers, growing consumer interest and government initiatives to encourage EV use with the goal of reducing emissions, EVs will likely become more common in the long term.

As uptake increases, EVs will place a greater load on distribution networks. Pricing which rewards consumers for charging outside of busy network periods will be important to minimise large investments associated with network upgrades.

Figure 7: Electric Vehicle Fleet Size (January 2014 – June 2017)



Source: Ministry of Transport – New Zealand Vehicle Fleet Statistics

Information from metering technology will help develop new pricing

The electricity sector has invested significantly in advanced metering infrastructure (AMI, known as smart meters). Smart meters measure more than just the amount of energy used (kWh); they can be used to measure demand, capacity, and other metrics of network use over time.

As of 2017, approximately 1.6 million smart meters are installed in New Zealand – double the number three years ago. This is a world leading position that should be used to improve outcomes for all stakeholders.

This technology infrastructure is the basis for a smarter grid that can be made cheaper and more efficient. It also provides the information foundation from which we can develop future types of pricing and manage networks more efficiently.

Distribution networks have changed to meet different demands

Distribution networks were developed to accommodate the sustained growth in demand for electricity. However, in several regions the rate of growth in demand now appears to be slowing or declining.

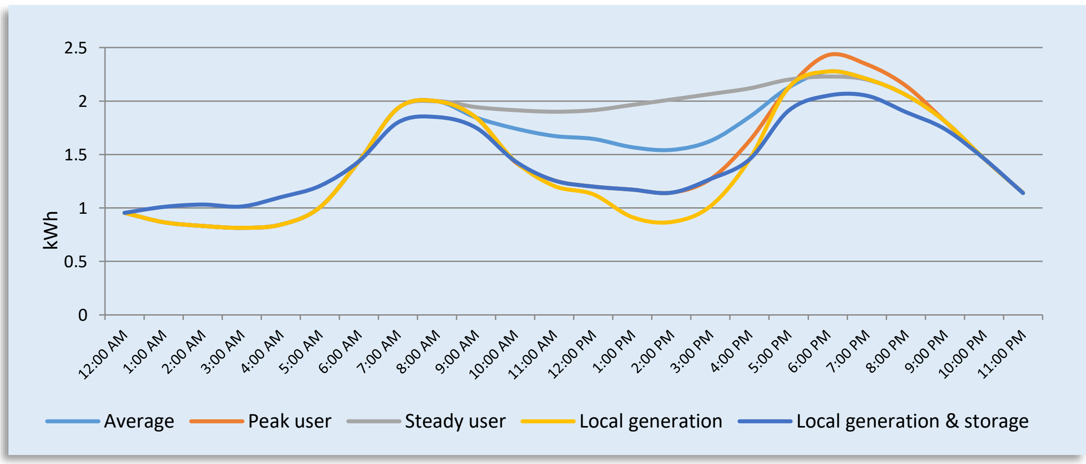
Network costs are guided by the demand for different distribution network services at different times of the day, rather than the total amount of energy that flows through the network, both of which vary across networks. This is forcing distribution businesses to rethink how they charge for the network services that they provide. Rather than charge primarily in $/kWh for total usage, they are looking to match prices for network services with the costs that they face. Some have already started making this change.

2.3 Pricing needs to evolve

Cross-subsidies create unfairness, inequality, and inefficiency

In the past, there was arguably less variation among different groups of consumers than there is today. Families generally lived in their own houses and mostly used similar amounts of electricity at similar times and nearly all electricity was grid-supplied. While discussion and debate about everyone paying a fair price for the electricity occurred in the past, the level of debate is likely to grow due to technology change.

Figure 8: Illustrative 2016 usage profiles



Source: ENA

This “fairness” situation has also changed as different consumption patterns have emerged. The changing situation raises questions about whether the current network prices are fair to all consumers. In the past, the consumption of electricity would likely have followed a pattern like the ‘average’ profile in figure 8 above – a peak in the morning and another at night.

In 2016, there are differences in the usage profile of different types of households, meaning that networks must now be configured and operated in new ways.

Figure 8 above shows that some consumers electricity use now has significantly greater impact on the network at peak times than do others, yet they each pay the same total charge for electricity. However, it is the peak demand that predominantly influences network costs.

The mismatch that is most important is how much consumers pay for the distribution network relative to the demands they put on it. This mismatch results in some consumers paying more than their fair share to subsidise others who are paying less than their fair share. The demand mismatch is now visible and measurable.

Some households that primarily use the network at peak times may pay less in network charges than consumers that place significantly less demand on the network during peak times and therefore cause less cost. Extending the figure 10 illustrative example using real world prices, the “peak user” consumes less energy than a “steady user” and so pays less in network charges.

Figure 9: Illustrative network charges for a typical weekday, by profile

	Average	Peak user	Steady user	Local generation	Local generation & storage
Total Network Charge	$3.50	$3.31	$3.72	$3.18	$3.24
% difference from the average	0%	-6%	6%	-10%	-8%
Network price per kWh = $0.09 for all users					
Network daily price = $0.15 for all users					

Source: ENA

Under current pricing structures, a consumer who has invested in battery storage, for instance, has little incentive to use this technology in a manner that reduces peak usage simply because there is no reward to the consumer for doing so. Existing pricing structures do not encourage the most efficient decisions on the use of energy sources:

- in some cases, they provide a less efficient incentive to use alternative technologies when grid-supplied energy would be more efficient; and
- in other cases, they do not provide enough incentive or reward to use alternative technologies.

Maintaining existing pricing structures will risk over-investment in distribution networks. Providing consumers with choice by pricing in a manner that reflects the services rendered and underlying costs of those services will help to better inform efficient investment decisions in technology. This has the potential to curtail distributor investment in additional network capacity, which in turn will help keep network prices down.

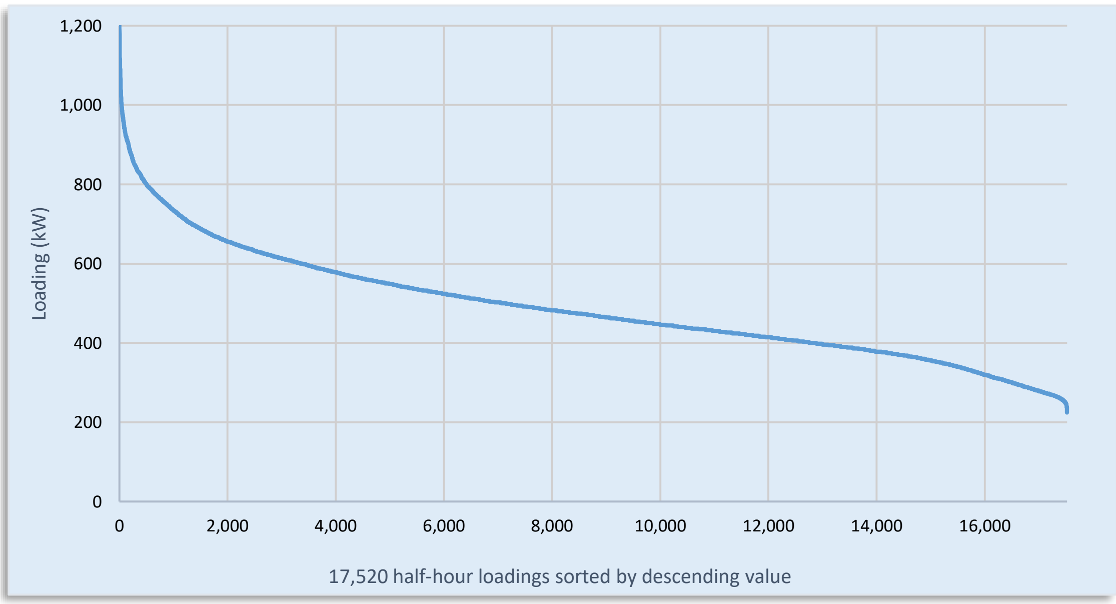
The benefits of pricing change

- Incentives to **use energy smarter –** it's not just about **how much** energy is used, but also **when** it is used
- **Lower prices –** in the long term, than what would otherwise occur
- **Sustainable distribution networks** – to support the new energy future

The importance of peak demand for network costs

The following chart shows why distributors must configure their networks to meet the peak demand needed for a very short period of the year. When many consumers are using electricity at the same time, this creates a demand peak on the networks. In this typical example, demand peaks at 1200kW for only a few half hours in the year (left hand side of figure 12) but for 85% of the half hours in a year, network demand is less than half that 1200MW peak.

Figure 10: Electricity demand over a year (highest to lowest)



Source: ENA

Therefore, peak demand, rather than the amount of energy consumed, largely dictates network configuration and cost for distributors. This is especially so in the transmission network but is also true in the high-voltage part of the distribution networks.

Pricing which signals peak periods to consumers will allow more efficient use of the network. Consumers may choose to shift some load outside of peak periods (for example, by charging an electric vehicle overnight when the network demand is relatively low) if pricing is set to reflect underlying network peaks and cost drivers.

The fixed costs of electricity networks

While forward-looking capacity upgrades are driven by peak network demand, a significant proportion of network cost is fixed and does not vary by changes to network use. For example, in the low-voltage network (which connects to residential service lines), distributors build and maintain poles, transformers and wires, or underground trenches and ducts in every street – regardless of how much electricity they supply. These costs, along with the overhead costs associated with managing an electricity network, are largely fixed, regardless of consumer numbers or electricity consumed.

Mismatches between pricing and costs are causing harmful effects

In summary, existing pricing is largely based on the total amount of energy consumed (kWh) whereas kWh does not affect distributors' costs of provision. Instead there are significant fixed costs associated with electricity networks (at a certain capacity kW) as well as network upgrades that are driven by demand during network peaks.

The mismatch between network pricing and costs under kWh-based pricing structures has the potential to lead to inefficient investments by consumers and distributors. Consumers therefore lack incentives to adjust their usage to reduce peak demand on the network and thereby save money through lower prices.

Figure 11: The drivers for change

Risk under current pricing		**Benefits under new pricing**
Inequitable and unfair	**< Individual >**	Ways to save money by using energy smarter
Inefficient investment	**< Community >**	Networks spend less in the long term which means consumers pay less than they otherwise would
Network viability	**< Network >**	Avoid leaving a cost burden to those least able to afford it

As an illustration of the magnitude of this cost, the Productivity Commission in Australia has identified cost savings of up to NZ$380 per kW of load per year across the transmission and distribution networks if these structural mismatches and subsidies are unwound.[7]

[7] See "Overview - Electricity Network Regulatory Frameworks - Inquiry report" Productivity Commission Australia.

2.4 International experience

The need for change is being recognised worldwide - other countries have seen similar developments and have responded by changing pricing structures.[8]

In Australia, a 2014 regulatory determination introduced a new rule that required distributors to set prices which reflect efficient costs.[9] The intention of the rule was to allow consumers to make more informed decisions about their use of electricity. Following that determination, Australian distributors have conducted extensive consultation and identified new pricing arrangements which they are now in the process of implementing.[10]

A 2016 report by the Rocky Mountain Institute is a useful reference for distribution pricing arrangements in the US.[11]. The report gives advice on pricing options to network utilities. It includes a comprehensive survey of the utility companies in the US which offer pricing that reflects costs, such as time-of-use (ToU) and demand-based types of pricing.[12] The report highlights that ToU-based charging can halve consumer energy peak consumption without compromising consumer acceptance.

We report in more detail on European studies on specific types of pricing in Part 3 of this report.

In New Zealand, there has already been some change to distribution pricing. In the central North Island, The Lines Company introduced demand-based pricing in 2007. Orion Networks in Christchurch also uses demand-based pricing. Seven networks have introduced ToU pricing that varies according to peak and off-peak period pricing. We will come back to these examples of pricing change in Part 3.

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[8] For detail on what is being discussed and proposed internationally a helpful reference is: The Regulatory Assistance Project (RAP) http://www.raponline.org/document/download/id/

[9] Australian Energy Market Commission (27 November 2014), Rule Determination – National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014. http://www.aemc.gov.au/getattachment/de5cc69f-e850-48e0-9277-b3db79dd25c8/Final-determination.aspx

[10] An example of an Australian distributors' new pricing initiatives is the *United Energy Tariff Structure Statement 2016-17* https://www.unitedenergy.com.au/wp-content/uploads/2015/09/UE-TSS-Submission.pdf For further information on Australian distribution pricing analysis see: the Grattan Institute (July 2014),"Fair Pricing for Power" http://grattan.edu.au/wp-content/uploads/2014/07/813-fair-pricing-for-power.pdf or KPMG Australia's paper on tariff reform http://www.ena.asn.au/sites/default/files/electricity_network_tariff_reform_handbook_may_2016.pdf

[11] The Rocky Mountain Institute's paper on alternate rate design is available at: http://www.rmi.org/alternative_rate_designs

[12] For peer reviewed literature in recognised journals, see Faruqui, A. and Sergici, S. (2013) "Arcturus: International Evidence on Dynamic Pricing". *Electricity Journal*, August/September 2013 Volume 26, Issue 7, pages 55-65.

3 Preparing for the future

3.1 The effect of consumer technology on distributors

We are now considering a future where consumers face different choices and opportunities for using energy. Technology changes include electric vehicles, storage batteries, solar and other local generation, and smart household appliances. The cause and effect relationship from these technology changes is not linear and singular in direction. Distribution network pricing will affect these opportunities, which in turn will affect the networks.

By way of example, the time of day when consumers recharge their electric vehicles will affect the capacity requirements of the distribution networks. If consumers all recharge their electric vehicles at the end of the working day, the evening peak will increase – unless the costs of the increased peak are signalled to them through efficient pricing. Consumers may then choose to recharge at another time when costs (and prices) are lower.

Likewise, the use of batteries by consumers could have a profound effect on networks. Battery prices are expected to fall, as batteries are more widely used. It is expected that consumers would charge batteries at off-peak times when energy is cheaper, and use them at peak times when prices are higher. Therefore, the use of batteries under current pricing structures means that distributors could need to regularly reset network prices across different services and times of the day and year to provide adequate revenue to the distribution business. This will not work in the long term.

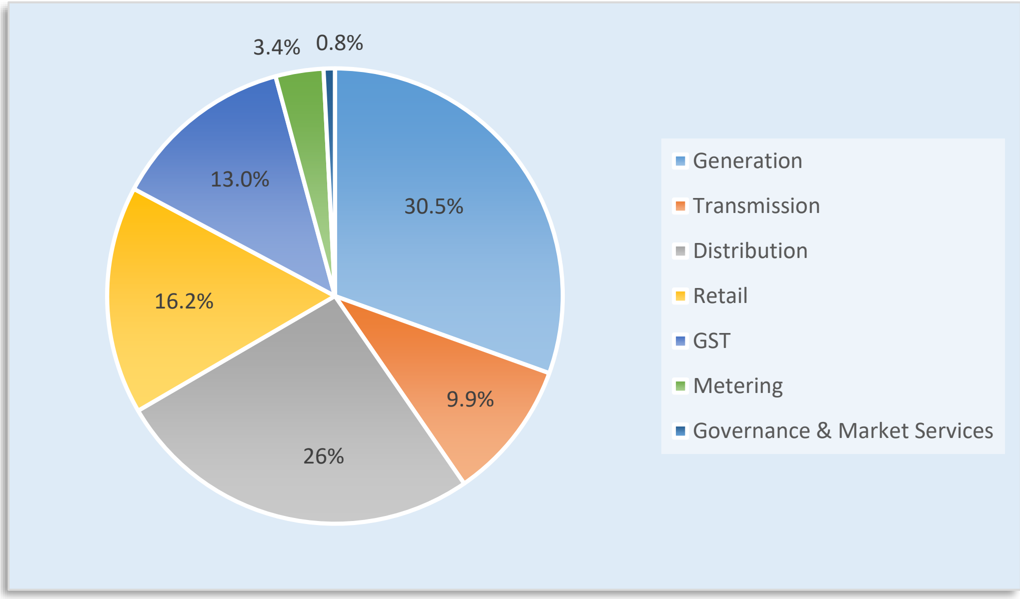
Regardless of how these opportunities unfold, consumers must be able to make their choices based on electricity pricing that is fair and rational for both them and for the distribution business that provides the network connection to their premises. Rather than try to guess the future, the industry need to prepare for a wider set of possibilities with well-structured prices that communicate effectively with consumers.

3.2 How retail prices would be affected

Retailers recover distribution charges from consumers. Distribution charges account for around 26% of the bill sent to consumers, with transmission charges accounting for a further 10%. Transpower charges distributors for the transmission network costs which are then passed to retailers for billing to end consumers.

Retailers can either pass the distributor's pricing structure directly to consumers, or repackage the charges – for example, into an existing kWh charge. If a demand charge is passed through directly, consumers can see network peak pricing signals. Repackaging by retailers may well dilute or negate the price signal.

Figure 12: Components of retail prices



Source: Electricity Authority

Ultimately, consumer preferences are a key determinant of the structure of retail prices. Retailers compete to win customers. If a retailer implements a pricing structure that consumers do not like, it will lose market share and need to revise its pricing to win customers back.

From the consultation that the DPWG has done so far, it is apparent that retailers generally accept and understand the reasons for distributors to change the way that they charge. Retailers prefer consistent price structures from distributors, and a degree of simplicity, both of which make implementation easier. Shifting to a new pricing structure is significant for both distributors and retailers. Both sides need to collaborate and allow enough time for change to happen.

3.3 Our process for developing types of pricing

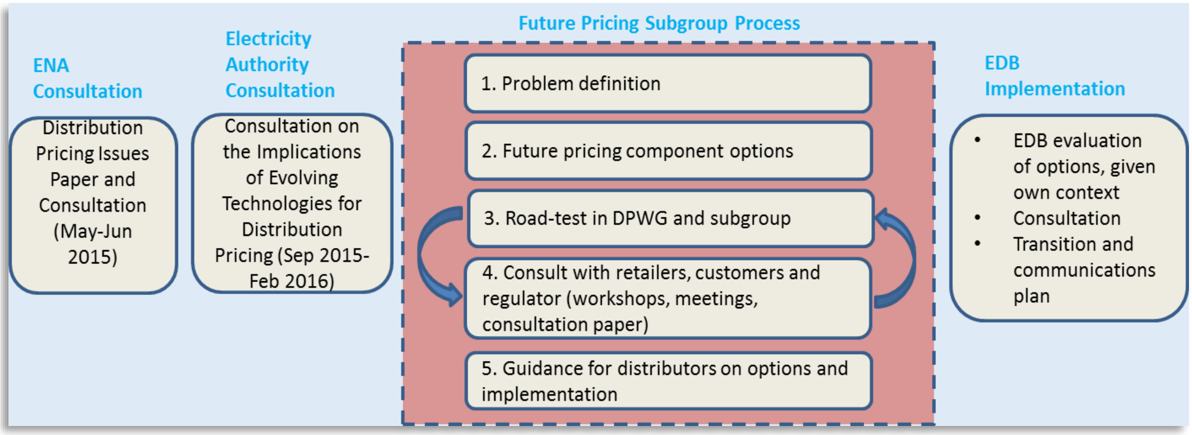
The task of developing durable and efficient distribution network pricing is part of an ongoing process. The ENA carried out an initial consultation on distribution pricing with an issues paper in May 2015. The EA further examined the issues in a consultation process which ran from late 2015 to early 2016.

In preparing these guidelines (as described in the diagram below), various types of pricing, and implementation approaches, were first tested through discussion among distributors. Input was then sought from the following stakeholders:

- Retailers: through meetings with a sample of individual retailers, a survey of all retailers, a stakeholder workshop and feedback session, and meetings with ERANZ (Electricity Retailers' Association of New Zealand);
- Consumers: consumer representatives were invited to a stakeholder workshop and feedback session, with follow-up contact, while ENA commissioned UMR to hold four consumer forums early in 2016;
- Regulators: meetings with the EA to provide updates on progress. Regulatory representatives also attended the stakeholder workshops and feedback sessions.

A report was then issued for consultation. Twenty-one submissions were received. A summary of the submissions is available on the ENA's website. The input received from stakeholders has been considered in the preparation of this guidance paper.

Figure 13: Where our process fits



Source: ENA

The results of change may take time

The task to reform pricing is not straightforward or as simple as this process diagram may suggest. There is a broad series of priorities to consider and the implementation of pricing reform will involve complex trade-offs and risk. A great deal is unknown about how the technology and market drivers of change will affect consumers in the future.

The specific local environment of each distribution business will reflect how it reforms pricing. Transition could take years before success is measurable.[13]

[13] In April 2017, all distributors published roadmaps of their transition to more cost reflective pricing. There was a variety of approaches to both the process of pricing reform and to the timing of change. Some distributors propose trials of specific options as soon as 2017 while others are looking beyond 2020 to start the process. The roadmaps provide valuable visibility to all stakeholders about when and how pricing arrangements will change. It is planned to update these roadmaps 6 monthly to keep them current and maintain their value to stakeholders.

4 Network costs and pricing: an overview

Compared to existing pricing, new pricing structures better reflect the services provided by distributors and the underlying costs. This section provides an overview of electricity network cost structures and discusses cost-reflective pricing types.

4.1 Electricity network costs

Understanding distribution network costs

Distribution network assets are mostly associated with either the low voltage (LV) or high voltage (HV) parts of the network.

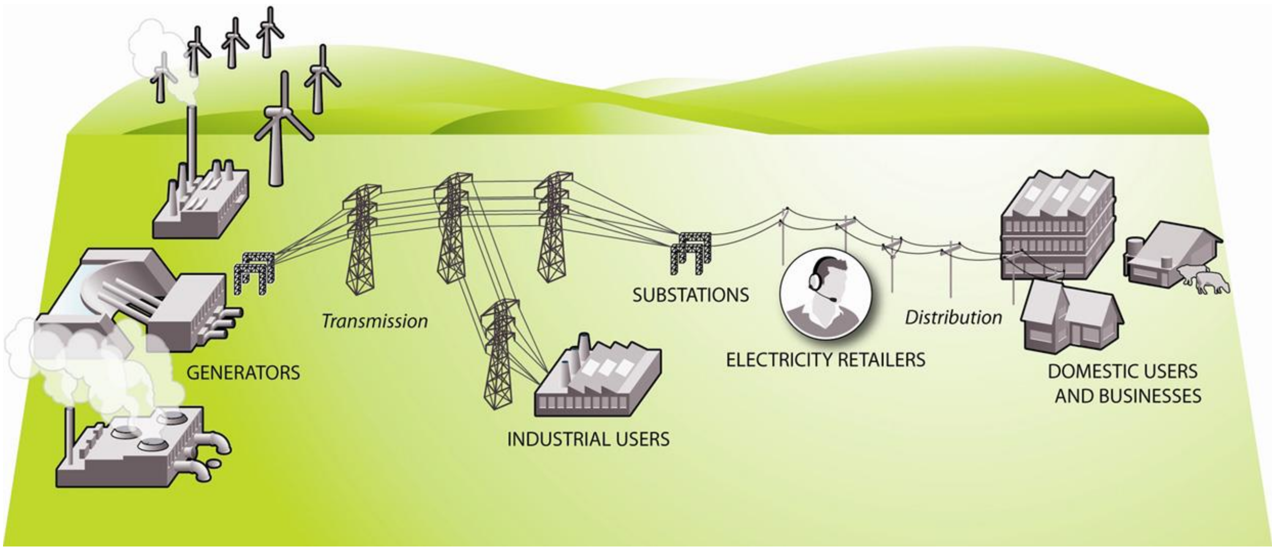
The HV network transmits electricity from a point of connection to the national grid - called the Grid Exit Point – to zone substations (typically at 66kV or 33kV) and distribution transformers (at 11kV or 22kV). Electricity supply is then stepped down to the LV network, which carries electricity at 400V from the distribution transformer to the consumer's connection point.

Service lines connect the distribution network (the fuses at the connection point) to the consumer's switchboard, which is typically owned by the consumer.

The capacity required on the HV network is driven by the "coincident" peak of the total load across large numbers of consumers. Distributors upgrade the HV network as required when peak loads increase.

The LV network has a much greater degree of customer dedication with capacity requirements being driven by a relatively small number of consumers within a localised area. Distributors build LV networks according to the expectations of typical local capacity requirements. In residential areas, the need to upgrade LV networks is generally reasonably limited (although changes in the use of new technologies could well alter this).

Figure 14: Electricity network diagram



Source: Ministry of Business, Innovation and Employment

Distributors' total costs include:

- Network costs, which involve:
  - The capital costs associated with investing in both LV and HV assets[14]
  - Network operational and maintenance costs. For example, the cost of field staff to maintain the network, restore faults, vegetation control, etc.
- Non-network costs include some capital costs (buildings, vehicles, etc.) as well as operational expenditure associated with managing a distribution network business.
- Pass-through costs, of which the largest is transmission grid charges payable to Transpower.

Many network costs are fixed or sunk

Electricity lines businesses face many fixed costs associated with their distribution networks. Fixed costs are costs that don't change with the quantity supplied. A distributor's overhead costs, for example, are generally fixed. There are also fixed costs associated with the LV network because of the need for poles (or underground ducting) and lines down every street, regardless of the capacity supplied.[15]

Distribution networks also involve very high levels of "sunk costs". These costs, such as past network capacity investments, have already been incurred and cannot be avoided in the future even if demand reduces. A challenge for distributors is how to recover these costs in an efficient manner that minimises distortions to consumer demand.

Capacity upgrade costs driven by network peaks

A large proportion of network costs are driven by the load requirements. As noted above, for the LV part of the network, the relevant load is within a small geographic area, and within residential areas there is generally little need for LV network upgrades. HV network capacity is determined by the coincident network peaks and distributors must make large "lumpy" investments for capacity upgrades. In other words, when the HV network peak load approaches capacity there is a high "step change" in cost associated with capacity upgrades to accommodate even a small increase in demand.

Network loads generally peak in the morning and evening, reflecting typical residential consumer demand patterns. Most distributors experience their highest network peaks during winter, although in some regions networks peak during summer (for example, in parts of Canterbury where there is significant irrigation).

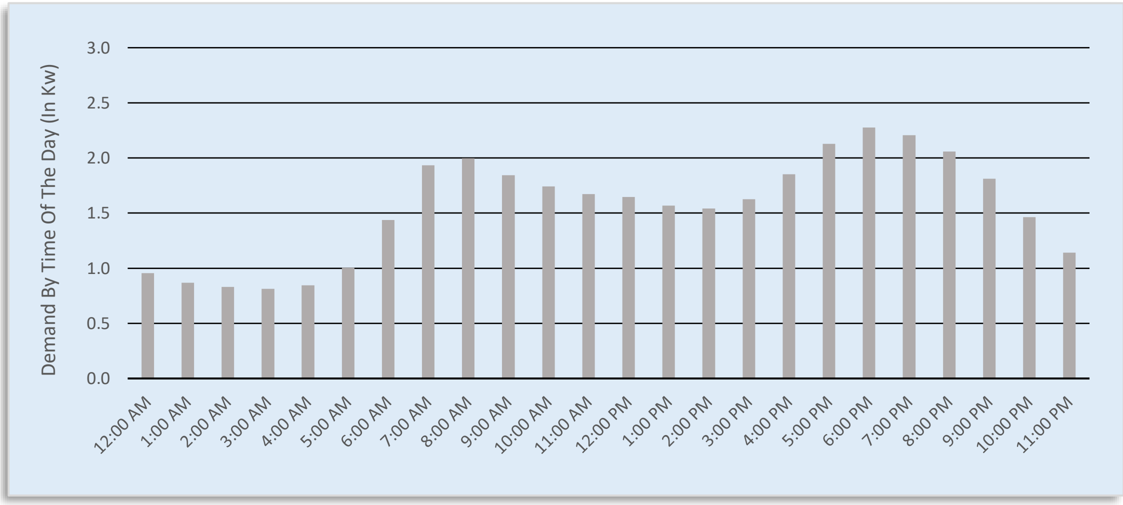
Figure 15 illustrates the change in the amount of energy consumed at different times of the day for a typical residential consumer. In this example, the evening peak is approximately 2.5 times the lowest level early in the

[14] Recovered through depreciation and a cost of capital allowance (where the latter provide a reasonable return on capital).

[15] To a lesser extent this is also true for the HV network.

morning. Energy consumption through the day is generally charged at the same variable retail price of about 29c/kWh, of which around 36 percent covers network costs.

Figure 15: Demand peaks – illustrative example for residential consumers



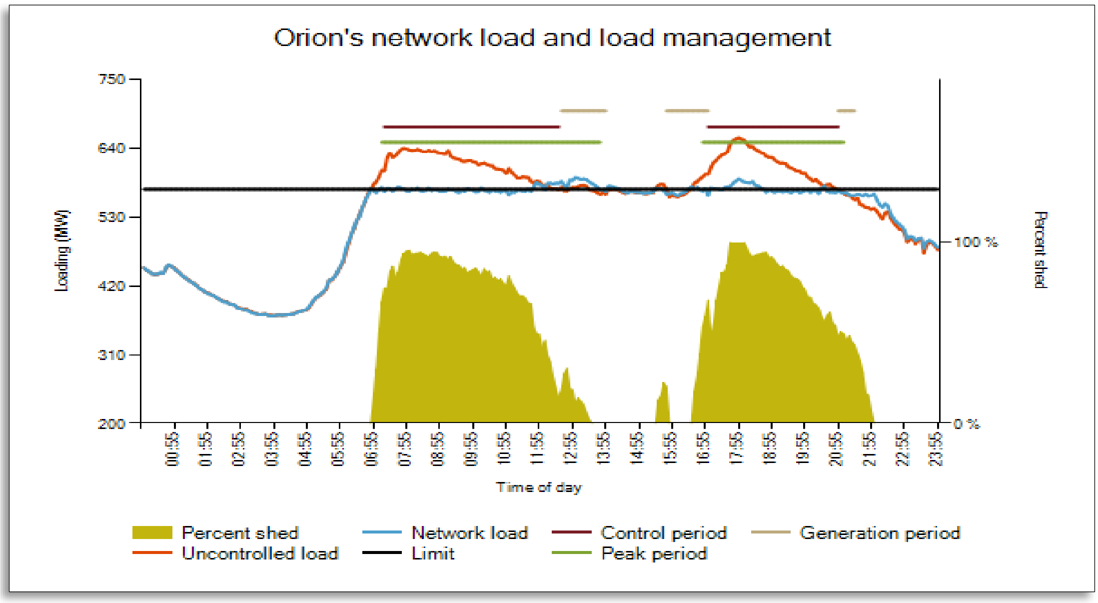
Source: ENA

Managing network peaks

An effective means for managing peaks, particularly when peaks occur on cold winter days, is using hot water load control. This method of load management is used by most distributors in New Zealand. Where this approach is available, consumers choose types of pricing that allow distributors to use a "ripple" control system which switches off hot water heating for short periods during peak demand. Peak load control is generally operated according to a set of service level targets to minimise the effect on consumers (for example, to avoid cold showers). Figure 16 and Figure 17 below show the effectiveness of load control programs, using the example of the upper South Island load control program on a cold winter day[16]. In figure 16 (for Orion's network) the red line shows the network load that would have occurred *without hot water load control*. The blue line shows the actual network load that occurred *with the load control programme* in effect. In this case, load control substantially reduced the peak load on Orion's network. The result is a very flat load profile, as can be seen from Figure 17. The morning and evening peaks that would have occurred without the load control on both Orion's network, and the upper South Island region, have been almost completely smoothed. Though not visible in the figures, tens of thousands of consumers chose to have their hot water heated only at night, reducing the peak loadings much further.

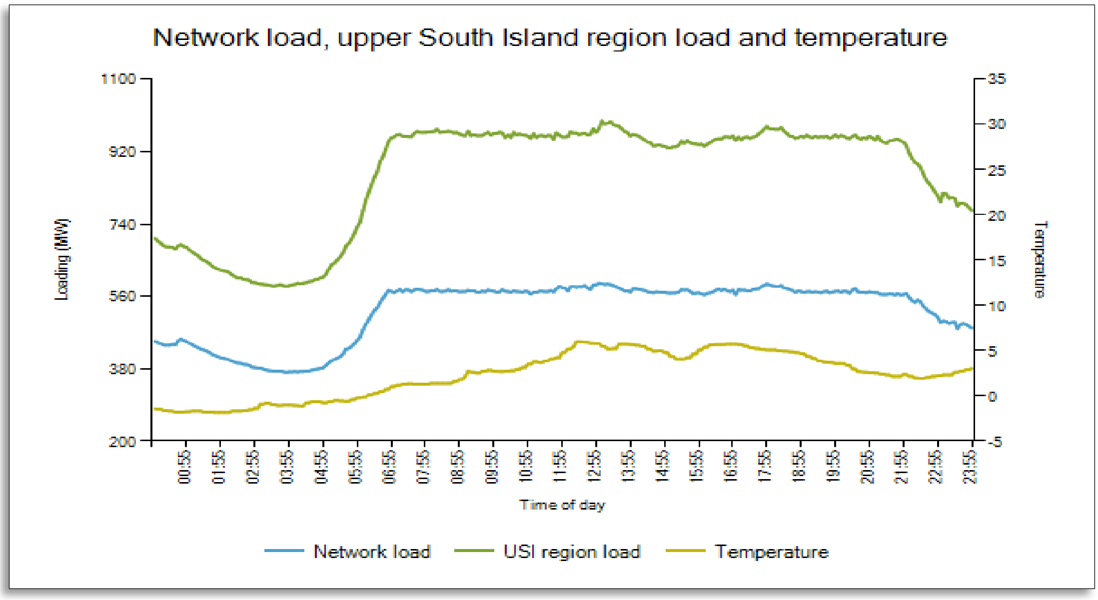
[16] Further information and charts available at https://online.oriongroup.co.nz/LoadManagement/default.aspx

Figure 16: Orion network load and load management, 8 August 2016



Source: Orion

Figure 17: Network load – Upper South Island region and Orion network, 8 August 2016



Source: Orion

The smoothing of network peaks through hot water load management can avoid, or at least defer, many millions of dollars of investment in distribution and transmission networks. Consumers benefit from offering up interruptible load and receive lower network prices over time.

As discussed in section 2.1, distributors typically reward consumers who have their hot water connected to load control with discounted prices. It is important when considering new pricing that distributors consider the impact on the reward consumers get for choosing to have their hot water heating controlled. For example, when considering demand charging a relevant factor to consider is that a consumer's demand can increase rapidly when the hot water load is turned back on. It is important that the consumer is not penalised for this increase in demand that is, in effect, created by the network.

There is some anecdotal evidence that consumers are becoming less inclined to connect their hot water cylinder to load control, either simply because of a preference not to connect or because they have their own load management system or other hot-water heating alternative (for example, gas). The possibility that this becomes a significant trend further supports the need for cost reflective pricing. In other words, pricing that effectively signals times of constraint on the network will encourage those consumers who manage their load to do so efficiently, and encourages efficient choices (ie, where a consumer will opt out of load control only where the benefit from doing so exceeds the costs that it causes).

4.2 Cost-reflective pricing

The nature of distribution network costs – high fixed and sunk costs accompanied by lumpy investments for capacity upgrades – means that developing prices that reflect costs is not a straight-forward task. In what follows we draw on findings from the economic literature on what an efficient cost-reflective distribution price might look like.

Reflecting upgrade costs of network peaks

Efficient distribution pricing has the benefit of signalling to consumers the long-run cost of capacity upgrades.[17]

This is often referred to as long-run marginal cost (LRMC) pricing.[18] 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, when consumers' use of electricity for heating pushes demand to its highest.

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[17] Economic theory on cost recovery focuses on the effect of pricing on welfare. Welfare is defined in economic theory as the sum of producer and consumer surpluses (the areas above and under, supply and demand curves respectively up to the level of consumption). Theory states that welfare is maximised when price is equal to the marginal cost (P=MC). When P=MC, a price signal will encourage consumers to choose a level of consumption that maximises welfare. If P≠MC, consumers will not consume at the optimum level, reducing welfare and causing what is known in economics as a dead weight loss (of welfare).

In most network companies MC in the short term is zero, because the change in network capacity is low to non-existent. However, over the long run capacity will change, so economists use long run marginal costs (LRMC) to determine the level of output which maximises welfare. That is in terms of network pricing, welfare is maximised when LRMC = P.

From a theoretical point of view, it is important to use LRMC when calculating distribution network prices, to send to consumers a pricing signal which will optimise the level of both consumption and hence welfare. Examples of LRMC based pricing include; ToU, critical peak pricing, peak demand charges and capacity based pricing. The application of this theory in practice is to be worked through by a new ENA workgroup so that distributors can share a common understanding of the role of pricing versus cost recovery.

[18] For more information, refer to the NZ ENA paper authored by Stuart Shepherd, and N. Matosin for Sapere Research Group, entitled "Pricing guide for electricity lines services" (2012). EDBs can also refer to the 2005 industry document "Model approaches to distribution pricing" authored by the Pricing Approaches Working Group. A copy of this document is available upon request.

Pricing according to critical peaks would reflect cost drivers. But most consumers may not understand or like this form of pricing. While the need for pricing that reflects critical peaks will depend on how congested the distribution network is, this need varies across the different networks. For example, distributors with significant excess network capacity may not need to give consumers a strong peak pricing signal.

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.

Recovering fixed and sunk costs

In the presence of fixed costs, prices based on LRMC will not recover total costs. Distributors face the challenge of how to recover the large pool of fixed and sunk costs in a fair and efficient manner. Economic theory finds that when recovering these costs (called residual costs in the literature) it is important that distortions to consumers' electricity usage decisions are minimised.

Fixed pricing is often used in this regard.[19] Under fixed pricing, consumers do not gain from changing their consumption behaviour. Fixed pricing provides a relatively simple means for covering residual costs with minimal distortions to economic efficiency. However, charges based on fixed costs do not necessarily reflect wider network cost drivers. This can result in higher fixed prices that may be unpalatable for some small consumers, and could drive these types of consumers to disconnect from the grid. Where the level of fixed prices is constrained, either explicitly (through regulation) or implicitly (due to potential consumer response), an approach that uses capacity (or demand) prices can provide a more efficient and fair way to recover the remaining fixed costs, than say consumption-based prices. In combination with such an approach, LRMC pricing would reflect that the key service purchased by electricity network consumers is their access to network capacity.

Distribution pricing – simplicity or efficiency?

There are other considerations relevant to designing network pricing than just theoretical efficiency gains. These considerations are discussed throughout the paper and are included in the criteria that are used for measuring the effectiveness of potential pricing methods. Because of the (more-or-less) unique circumstances of each distributors local environment, the trade-offs between the criteria will be complex and involve risks to the business. Despite this there are opportunities for distributors to work together and share learnings. Early adopters can provide other distributors with valuable data and experience to work from.

A key tension that distributors will need to resolve is the relative focus on simplicity versus efficiency in determining pricing. The most theoretically efficient pricing structure may be a combination such as described

[19] According to the literature researched for these guidelines, residual costs (the difference between the total approved revenue and the revenue that would be raised at tariffs based only on LRMC), should be recovered through a **fixed charge** that *does not* send a price signal to consumers to alter their consumption behaviour. The level of consumption (capacity) is ideally set by consumers following a price signal set by a LRMC based charge. For more research see the Brattle Group's paper on recovery of residual costs https://www.hks.harvard.edu/hepg/Papers/2014/Brattle%20report%20on%20structure%20of%20DNSP%20tariffs%20and%20residual%20cost.pdf. Conversely a fixed charge should not be used to recover LRMC as no signal can be sent.

in the previous section, but may not be immediately acceptable to consumers or retailers. A simpler, but less efficient type of pricing, may therefore be more effective in practice if it results in greater uptake by consumers.

Time-of-use (ToU) pricing stands out as offering simplicity and ease of understanding for consumers because it already exists in a simple form. But it would result in a less efficient outcome than a pure demand charge because ToU is less cost reflective. It may also be less effective and fair in the long term than a demand based pricing. There are transition paths that can start with simpler types of pricing and then migrate to more efficient, though possibly more complex pricing structures.

Part 3 discusses types of pricing and gives a detailed assessment of each against the criteria that represent long-term, efficient outcomes.

We have not recommended one particular option

This paper stops short of promoting specific types of pricing. To do so would require knowledge of the circumstances that would drive a distribution business to choose among the types of pricing presented. It is not possible to do that analysis or to consider the necessary trade-offs on behalf of each distributor.

However, it should be recognised that, given the number of network businesses in New Zealand, it is wise to encourage alignment by identifying a key set of pricing for distribution businesses to focus on.

There are two broad categories of pricing that can be used to better reflect costs than simple flat-rate consumption pricing. These are:

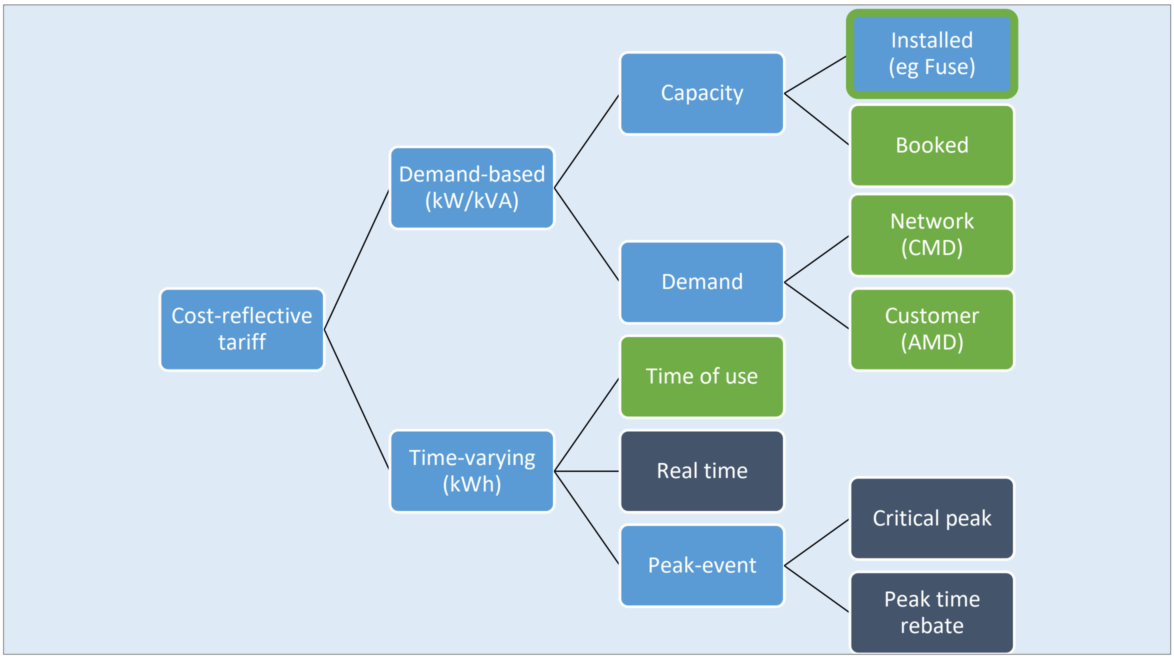
- time-varying consumption pricing, where the price per kWh of energy used varies at different times of the day or year
- demand-based pricing, which is applied to the load or capacity requirements of the customers, as measured either in kW or kVA. Figure 18 sets out several types of pricing that fall within each of these two categories.

The ENA focuses on five cost-reflective types of pricing that could represent a first phase of pricing reform. Some are simpler than others, while some are more efficient. The five for review are highlighted in green in Figure 18, and are described and assessed in detail in Part 3 of this guidance report. We have also included installed capacity, an option that does not require smart meters.

Real-time pricing and peak-event pricing are not considered further in this guidance paper due to the complexities involved. It is also not clear whether real-time pricing would be consistent with the existing regulatory framework, and would likely require the development of systems to inform end consumers of price changes. Similarly, peak-event pricing would require technology or systems to inform consumers of peak events.

A future 'second phase' of pricing evolution could explore more localised, cutting-edge pricing that enables the full optimisation of smart technologies, communications and distributed energy. This would potentially be the most efficient pricing in the long-term. For example, network businesses might offer specific incentives in congested parts of their networks for consumers to reduce their peak demands, such as through peak time rebates.

Figure 18: Types of pricing



Source: ENA

Within the time-varying consumption pricing category, specific types of pricing per kWh include:

- Time-of-use, which is pricing that varies according to the time of day that energy is consumed
- Real-time pricing, which is pricing that changes in real time (for example, hourly) as is the case in the wholesale energy market.
- Peak-event pricing, where either:
  - higher prices per kWh of consumption are charged during periods of peak demand to encourage consumers to use less power at those times – critical peak pricing; or
  - a rebate is given to consumers who reduce power use during periods of peak demand. Examples of events that might trigger this type of pricing include weather events, extremely cold days when very high use of heating contributes to high network loads. Peak events are typically signalled to consumers in advance to enable them to respond.

Within the broader demand-based pricing category are capacity prices, which apply to situations where the consumer selects the capacity to be made available, and demand prices where the consumer is charged based on the amount of capacity that he or she uses. Specific types of capacity and demand charges include:

- Installed capacity, where the price is applied to the maximum capacity provided by the physical fuse size.
- Booked (or “Nominated”) capacity, which is pricing that reflects the load capacity that a consumer chooses with a periodic assessment of whether the consumer’s actual load has remained within that booked capacity. Smart meters can be used to provide a range of booked capacity options.
- Customer peak demand pricing is applied to the consumer’s actual maximum demand at any time.
- Network peak demand pricing is applied to the consumer’s demand at network peak times.

4.3 Clarification of regulatory constraints on types of pricing

There are several regulatory considerations regarding pricing. These are explained in detail in Appendix C. Of most relevance to the issues discussed in these guidelines are the regulations that relate to the structure of prices rather than the price levels. The Low Fixed Charge Regulations (LFC Regulations) place constraints on the level of fixed prices that can be applied for residential consumers who use less than 8000 kWh per year (9000 kWh in certain regions). A distributor's daily fixed price in respect of those consumers must be no more than 15c per day. Similarly, a retailer's daily fixed price for those consumers must be no more than 30c per day.

There has been uncertainty as to which types of pricing structures are fixed and those considered variable. In response to requests for clarification, the EA has published a set of guidelines (the LFC Guidelines).[20] The clarification set out in the LFC Guidelines has direct implications for the types of pricing examined in this guidance paper.

Regarding the pricing types considered in this paper, the LFC Guidelines make the following clarification as to which prices would be considered variable and therefore not restricted by the LFC Regulations:

- Consumption charges, including ToU consumption charges, are variable. This is because consumption charges relate to the amount of electricity consumed.
- Demand charges, including Customer Peak Demand and Network Peak Demand, are variable. The EA explains that demand charges are based on the amount of electricity consumed during one of more identified measurement periods.
- Capacity charges are variable, if the consumer can change his or her level of capacity. The EA states that:

> *"A capacity charge that varies according to the amount of electricity a consumer expects to consume is a variable charge. So, capacity charges are variable – provided the consumer can change its capacity* ***at a reasonable cost and in a reasonable time period****, and so change the amount of the capacity charge that will apply. If in practice the consumer is unable to affect the amount of a capacity charge, then that charge would be considered to be a fixed charge."*
> *(Emphasis added)*

There are also restrictions in the LFC Regulations on tiered or stepped variable charges.

We note that it is up to each distributor to review the LFC Guidelines and weigh up the regulatory risk of any pricing option. The EA as the enforcer of the LFC Regulations has set out its view on how the regulation should be interpreted. Risks associated with legal challenges to that position, political response and how subsequent consumers receive price changes are matters for each individual distributor to evaluate.

[20] Electricity Authority (August 2016) *Variable charges under the Low Fixed Charge Regulations – Guidelines* available at http://www.ea.govt.nz/development/work-programme/evolving-tech-business/distribution-pricing-review/development/guidelines-for-low-fixed-charge-regulations/

4.4 ENA approach to examining types of pricing

The ENA took a straightforward analytical and assessment approach to examining pricing options. As described earlier, we identified the drivers for change as well as the types of outcomes sought from future pricing, and then assessed the types of pricing against a set of criteria that we believe are good indicators of whether particular types of pricing can deliver those outcomes.

This report considers several types of pricing. It focuses on those that we see as the best candidates for a first phase of reform. The sections of the report that follow in Part 3 analyse and assess the types of pricing.

Part 2

Consultation with stakeholders – consumers and retailers

5 Stakeholder engagement

Engagement with stakeholders is critical to the success of any changes to distribution pricing. This includes good communication describing the need for change, consultation on the development of tariffs and an effective engagement program during the implementation of and transition to new pricing. The ENA supports the Australian Energy Networks Association's (Australian ENA) view on stakeholder consultations regarding obtaining and preserving a "social license" for pricing changes (see sidebar).[21]

> *"Distributors must obtain and preserve a social licence to implement network tariff reform as reform has the potential to affect every electricity customer. Distributors recognise that to develop and maintain this social licence to help undertake this reform they must:*
>
> - *Explain the case for change and the customer benefits it will deliver;*
> - *Work closely with other stakeholders and be open, transparent and equitable in all of their dealings (including equipping customers to reap the benefits of reform); and*
> - *Be willing and able to adapt and change over time, including as new learnings emerge from the staged implementation of the reform."*
>
> – ***2016* Electricity Network Tariff Reform Handbook**

Distributors have two main groups of stakeholders - electricity consumers and electricity retailers. For some networks, generators are also stakeholders.[22] Beyond these immediate stakeholders, distributors should also consider engaging with regulators, social agencies, Transpower as grid owner and system operator and metering equipment providers. Whether these stakeholders are engaged will depend on the scope of any changes and each individual distributor's circumstances.

In what follows we discuss in detail:

- Consumer engagement during the consultation phase;
- Retailer engagement during the consultation phase; and
- Stakeholder engagement during implementation and transition towards new pricing structures.

5.1 Consumer consultation

Why consult with consumers?

Successful pricing discussions need to focus on the end consumer. Consumer engagement delivers better outcomes for consumers and supports the success of any change. As stated by the EA:

"…distribution pricing structures around the country will best promote the long-term benefit of consumers when design is informed by local knowledge. Distributors

[21] ENA Australia - Electricity Network Tariff Reform Handbook, Draft for Consultation April 2016, pg 5.

[22] The ENA convened a customer engagement working group in September 2016 to allow members to share resources and knowledge and to develop primary research regarding customers and electricity consumption, including pricing.

can achieve this by actively and effectively engaging with the consumers and retailers on their networks when developing distribution pricing structures."[23]

Effective engagement requires meaningful consultation supported by detailed analysis of the effect of any change on consumers, recognising the increasing diversity in consumers' use of electricity services.[24] Distributors need to consult with consumers because:

- consumers provide invaluable feedback and insight about the communities served by the distributor that will support the development of durable pricing structures
- in many cases, the distributor is at least partly owned by its consumers
- regardless of ownership, the distributor still needs to obtain buy-in from the end consumers of electricity to ensure that it has considered the needs of its communities. Equally the community needs to understand the constraints on distributors.

Engagement cannot be done in isolation. As a minimum, distributors need to alert retailers as to any consultation they propose undertaking with end consumers. It may be that retailers wish to have input into the customer engagement. It is important that the distributor makes it clear that the consultation is only concerned with the lines charges component of the customer's electricity invoice.

Discussions with end consumers need to be framed along the lines that the distributor is exploring or researching options and that an outcome cannot be predetermined.

The ENA, in coordination with ERANZ, is developing engagement guidelines for distributors which will be of assistance to distributors when undertaking this engagement.

Guidance on consultation

The Australian Energy Regulator has identified four principles that should guide a company's interactions with its consumers:

- communication needs to be clear, accurate and timely
- interaction needs to be accessible and inclusive
- companies must aim to be transparent in their dealings with consumers
- the outcomes of the consultation need to be measurable.

Distributors may wish to draw on the Integrated Association for Participation (IAP) guidelines for consultation. This approach is used by government organisations (such as territorial authorities and state-owned enterprises) to consult on community projects like town planning, infrastructure, and rates. This is only one model and there are other interaction guidelines, some of which have been referred to in the Australian Customer Engagement handbook. The IAP guidelines specify five stages of consultation (discussed in Figure 19 below). The Australian literature suggests that companies should aim to do more than inform, but not necessarily to the extent of empowering, when engaging with consumers about pricing reform.

[23] Electricity Authority, November 2015, Implications for evolving technologies for pricing of distribution services – consultation paper, p 3.

[24] Electricity Network Tariff Reform Handbook, Draft for Consultation April 2016 pg 9.

Figure 19: Five stages of consultation

INFORM	CONSULT	INVOLVE	COLLABORATE	EMPOWER
• Provide the public with balanced and objective information to assist them in understanding the problem, alternatives and opportunities, and/or solutions.	• Obtain public feedback on analysis, alternatives and/or decisions.	• Work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	• Partner with the public in each aspect of the decision-making, including the development of alternatives and the identification of a preferred solution.	• Place the final decision making in the hands of the public.

Source: International Association for Public Participation (IAP2) www.iap2.org.au; AER – Consumer Engagement Guidelines for Network Service Providers, Explanatory Statement p 23.

Audience

Every network consists of many different types of consumers. Feedback across all consumer groups is needed through the consultation process to ensure a complete view of the impact of any price changes.

This could be achieved through direct engagement with consumers in focus groups of residential and small business consumers (including both urban and rural consumers if relevant). Examples of other groups a distributor might discuss pricing changes with are:

- trusts (or other owner representatives)
- councils, about street lighting and other community facilities
- consumer representatives such as GreyPower, Federated Farmers, Major Electricity Users Group or Sustainable Electricity Association New Zealand.
- advocates for vulnerable consumers.

Each distributor's employees and directors can also provide a valuable perspective and help to disseminate information within their communities.

Because of industry transformation, the traditional range of consumers (as identified above) is shifting. A distributor may now have:

- traditional end-use consumers who take energy from the network
- "prosumers" who consume and supply energy
- new and existing service providers and other market providers who collaborate and compete with businesses to provide energy management services to end users.

Consultation with these new types of stakeholders requires greater knowledge of how consumers interact with energy. The Australian Energy Network Transformation Project [25] classified consumers along the following continuum:

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[25] Electricity Network Transformation Roadmap.

vulnerable ⟷ engaged (passive or active) ⟷ empowered

These classifications are not fixed and consumers will likely move across the continuum over time and through their different life stages. In the future, industry experts predict the bulk of consumers are likely to fall within the engaged group.[26] It is more difficult to segment consumers based on their attitudes to and interaction with energy, than by industry group. This type of segmentation will require extensive engagement to determine attitudes, needs and motivation.

In this context, vulnerable consumers are those for whom the electricity bill forms a relatively large part of their household expenditure and they do not necessarily have the ability to change their consumption either in terms of shifting activity or changing appliances. Engagement with vulnerable consumers will be challenging however it is crucial that this group is engaged so that the impact can be measured.

Non-residential consumers can be segmented in the same manner, that is: vulnerable, passive - active and autonomous. The two most important factors identified by the Australian ENA in determining where a non-residential consumer falls on the continuum are the consumer's focus on energy:

- the amount of focused attention the organisation places on energy costs or technology
- the organisation's motivation and capability to change the way it interacts with energy.[27]

Effective consultation

The EA has produced 'Guidelines for consulting on distributor tariff structure changes'. They guide distributors on the scope, approach, and process of consultation on price structure changes. These principles reflect well-established principles of consultation and should apply to all consultation. Key features of the guidelines include the following:

- the distributor must approach the matter with an open mind, and be prepared to change or even start a process afresh
- there are no universal requirements on the form of consultation, and any type of interaction (whether oral or written) that allows adequate expression and consideration of views will be sufficient
- consultation must be allowed enough time, with genuine effort
- consultation involves the statement of a proposal not yet finally decided on, listening to what others say, considering their responses, and then deciding what to do.
- for consultation to be meaningful, the distributor must provide enough information to inform parties adequately, so stakeholders can make intelligent and useful responses.

However, consultation could fall within the EA's guidelines and still not be effective. Common elements of effective consultation that will foster mutual trust between the consumer and distributor include:

[26] Customer Engagement Handbook Engagement Draft April 2016, pg 7.

[27] Customer Engagement Handbook Engagement Draft April 2016, pg 8.

- adoption of a purposeful, planned, and transparent approach, involving:
  - a consultation strategy with clear scope, allowing sufficient time for responses
  - stakeholders in the development of a consultation plan
  - early consultation
  - collaboration with other organisations seeking to engage with similar groups of consumers and businesses.
- recognition of varying levels of consultation – effective consumer consultation recognises a scale of participation, like those in the IAP guidelines. Distributors will need to decide the most appropriate level of consultation for an issue. A one-size-fits-all approach to consultation is unlikely to succeed.
- meaningful dialogue – distributors need to ensure that consultation is conducted responsibly. This includes valuing the consumer feedback, reporting back to the community, and adhering to the principles of privacy, confidentiality, and respect. Engaging an independent facilitator may help.
- listening to and considering feedback – distributors must listen to consumers' feedback and concerns and ensure this feedback is appropriately considered in pricing designs and planning.

Best practice guidelines are being developed by the ENA to give distributors guidance on how to undertake this type of consultation.

Options for consultation

Recognising that a one-size-fits-all approach is not possible, a distributor will need to decide how to engage with its consumers. Enagagement strategies pursued by other networks internationally include engagement with consumers in a variety of ways;

- consultation events
- making information available on its website
- telephone and online surveys
- independent facilitators.

Although a planned approach is desirable, a distributor may need to change and adapt its approach through consultation. For example, while meetings can be an efficient way to gather feedback from several stakeholders, some stakeholders may be over-shadowed in a meeting forum. In such cases, it may be appropriate to go back and hold smaller meetings or interview those stakeholders individually. Also, initial engagement may highlight gaps in the identification of stakeholders. In such cases, the best option is to go back and engage with those stakeholders. Changes such as this can demonstrate to stakeholders that a distributor is responsive to their feedback.

Providing stakeholders with an overview of all feedback received can also be useful in eliciting further comments. It shows stakeholders that their input is valued as part of a wider process.

Challenges to effective consultation

Many of the challenges identified in Australia[28] are also relevant in New Zealand:

- Energy consumption patterns are not usually chosen and changed consciously. Related to this are the psychological, social, or emotional factors that affect a consumer's economic decisions. This means that a consumer may refuse an optimal solution, stay with a default, or focus more on potential losses than potential gains. This can be overcome by using an experienced research consultant and unbiased messages.
- The relative contribution of energy costs to a household's expenses or the running costs of a business can vary. Therefore, willingness to engage will vary, as will the quality of that engagement. Involving a diversity of consumers from across networks will give a balanced view so a distributor may consider offering incentives to participate. Alternatively, a distributor may consider using previous research stages to generate lists or consider forming advisory groups.
- Feedback about energy usage has traditionally been provided only infrequently to consumers, with little detail, and retrospectively. Accordingly, it may be difficult for consumers to engage meaningfully about electricity pricing.
- Consumers need to understand how a proposal might affect them directly. This can be difficult information to provide at the outset. SP Energy Networks in Britain found that it was helpful to provide tailored material to consumers during consultation that showed how changes will affect individual consumers[29]. In New Zealand, lines charges form only one part of the consumer's final bill. In most networks, the retailer sits between the consumer and the distributor. Discussions with electricity retailers have highlighted that several retailers believe that responsibility for communication about pricing with the consumer sits with the retailer. This can make it difficult to achieve engagement with consumers.
- Most distributors receive consumer contact information from retailers via Electricity Information Exchange Protocol 4 (EIEP4) files. The Privacy Act may constrain a distributor's ability to use customer information if there is no consumer contract between the distributor and the consumer or provisions in the Use of System Agreement. Where there is no contractual provision allowing a distributor to use the information from EIEP4 the distributor may need to consider other approaches such as opt-in surveys, relying on retailers to distribute invitations to participate in surveys, intercept interviews or stands at events such as A&P shows.

5.2 Consulting with retailers

Distributors will also need to work closely with retailers in managing the transition to new pricing structures. In some circumstances, retailers may be better placed to manage the consumer impact, given:

- they may have closer relationships with end-consumers

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[28] Customer Engagement Handbook Engagement Draft April 2016, p 9.

[29] SP Energy Networks 2015 -2023 Business Plan Annex Learning from Stakeholders, p 7.

- distribution charges are only one component of the final bill and retailers may determine how distribution pricing is passed on to consumers.

The principles outlined above, particularly the EA guidelines, apply also to consultation with electricity retailers. Consultation with retailers is more straightforward because they are readily identifiable, informed stakeholders and there is generally a pre-existing relationship between the distributor and the retailer.

Good industry practice suggests setting aside approximately 12 weeks to consult with affected retailers before deciding on prices. A typical timeframe is:

- Release a comprehensive written proposal (or methodology) detailing proposed changes to pricing structures with enough detail to allow retailers to make informed decisions
- Allow two weeks for retailers to request further information or to meet to discuss
- Allow two weeks to respond to questions or relevant information requests
- Allow a further two to four weeks for retailers to review new information and give feedback on the pricing proposals
- Allow two to four weeks to consider feedback, then decide and implement

For significant changes, a longer timeframe is recommended, as retailers are generally dealing with several proposals at the same time.

5.3 Engaging with stakeholders during implementation

Gaining consumer trust is essential throughout the implementation and transition period to ensure the success of pricing initiatives and avoid a potential backlash. This underscores the importance of building strong support with industry participants, regulators, government agencies, the media, retailers, and consumer representatives. It is vital to promote the consumer benefits of distribution pricing initiatives and build trust and credibility.

Submissions on the Consultation Paper emphasised the need for effective, transparent, and consistent communication and consumer education to minimise the impact on consumers. This recognises that consumers will be able to manage their own bills if they understand how the new pricing structures work. Due to potential rebundling, many retailers highlighted a need to avoid confusion over the actual prices that consumers will face (ie given potential rebundling). The consumer engagement guidelines developed by ERANZ and ENA provide some recommended principles to address these concerns while at the same time acknowledging and respecting the need for consumer engagement by distributors.

Figure 20 sets out some important considerations for engaging with other stakeholders during the implementation and transition period.

Figure 20: Engagement with other stakeholders

Stakeholder	Considerations
Retailers	Engaging with retailers throughout the transition period and beyond will help them: • develop retail pricing which either passes through or re-bundles distribution pricing signals • prepare their own transition strategies • prepare billing systems to avoid billing issues • prepare communication initiatives and consumer education • identify issues that might arise for them or consumers and provide feedback to distributors • adjust generation supply arrangements for potential changes because of changes in peak demand.
Regulators, social agencies, and consumer representatives	Engaging with these agencies will help them to: • identify, monitor, and report on consumer welfare issues • identify vulnerable consumer groups for targeted support, with potential help from social services and not-for-profit agencies • advocate on distributors' behalf the benefits of moving to pricing that reflects costs. A Grattan Institute report noted the important role government agencies and regulators can play in supporting the transition to future pricing.[30]
Media	Engaging with media is important to help them articulate the reasons why pricing is changing, and the benefits and risks to consumers of moving to pricing that better reflects costs.
Transpower, system operator, generators	Engaging will help these organisations plan for changes in how electricity is used at peak and off-peak periods, which in turn may affect their own investments. Distributors should liase with Transpower directly on the potential impacts of transmission pricing reform, which will likely impact consumer bills at the same time distribution pricing reform is progressing.
Meter equipment and meter data providers	Engaging with meter providers will help ensure that the necessary meter reading and data systems are in place for use in mass market pricing.

[30] See Grattan Institute ("Fair Pricing for Power") 2014.

Part 3

The types of pricing

6 Time-of-use consumption pricing

Time of Use (ToU) prices vary depending on the time of consumption. ToU prices have been employed in the electricity industry for years in the form of day/night charges and separately metered night charges. ToU pricing has also been common across the telecommunications industry to reflect the costs associated with utilising services during peak times.

Advanced metering enables consumption information to be recorded at a more granular level than legacy meters - every half hour during each day of the month, which provides the ability to target ToU pricing signals for different times of day and days of the week.

ToU pricing can also be used at a more aggregated point in the network, at the Grid Exit Point (GXP) level. “GXP pricing” of this type is used by distributors such as Powerco and Orion. In these guidelines, the pricing arrangements discussed are relevant at both individual consumer and GXP level.

Definition

While ToU pricing can refer to all charges that vary based on time of use for this guide, we limit the definition of ToU to the following:

> *‘ToU Pricing – a pricing structure where the prices vary based on energy consumption (kWh) during different times of the day and/or different days of the week (such as weekday, weekend). [Note: peak/off-peak or potentially also with a shoulder period]’*

6.1 Current experience

Currently seven distributors,[31] who provide line services to some 43 percent of consumers in New Zealand, have residential ToU pricing plans in place[32]. Some distributors have had advanced ToU pricing plans in place since 2010. Experiences of these distributors in designing and implementing their ToU pricing plans are summarised in Box 1.

[31] Excluding GXP-based ToU-based pricing methodologies.

[32] This does not include distributors who offer day/night or night only prices using legacy meters.

Box 1: Lessons from NZ implementation of ToU consumption pricing (distributor's perspective)

Drivers of ToU implementation

- Cost reflectivity was cited as the key reason for introducing advanced tariffs. ToU-based tariffs were a logical first step.
- Some distributors stated a preference for demand-based (kW) tariffs but were concerned by the potential for rate shocks and a lack of retailer support.
- Some distributors used ToU-based charges to test consumer and retailer reactions to more cost-reflective pricing with a view towards the future introduction of demand-based charges.

Price setting process

- The price setting process across distributors defined the peak periods and the relative pricing differentials. Peak periods were typically defined by network consumption patterns and then aligned to the network peaks of Transpower's regional coincident peak demand periods (RCPDs).
- Distributors were aware of the need to manage the trade-off between simplicity and cost reflectivity in setting their peak time periods.
- ToU pricing differentials were typically set by considering the short and long term costs incurred during these peak times (such as Transpower's interconnection charges and longer term costs associated with system growth) but then adjusting these to limit potential for rate shocks or revenue risk.

Consultation and promotion

- While all distributors conducted extensive consultation with retailers, there was little direct consultation, or promotion of the distributor's ToU pricing offer, with the end consumer.
- Retailers were generally supportive of the introduction of ToU pricing plans but some retailers have remained reluctant to create equivalent retail ToU offers.

Retailer and consumer feedback

- Retailers were generally appreciative of the reasons for more cost-reflective pricing and supported the introduction of ToU pricing over demand-based alternatives.
- A number of distributors also adapted their ToU pricing offers to widen their potential appeal to retailers. Despite this there has been limited response from consumers with fewer than 100 consumers across all distributors moving onto a ToU pricing plan.
- Retailers have suggested the need for strong alignment between ToU offers across distributors in order to help them conduct national campaigns. They also stated a preference for the simpler two-rate ToU (Peak & Off peak) option over the three rate (Peak, Shoulder & Off peak) option due to perceived consumer preference for simplicity, but aligning to these requests has not improved consumer take-up.

Other Learnings

- The LFC Regulations were highlighted as a restriction to the introduction of ToU pricing plans due to the complexity associated with ensuring any new ToU pricing plan also had a low fixed charge equivalent.
- Some distributors stated that they over-estimated the risks associated with sudden voluntary uptake of ToU pricing plans, which potentially affected the initial take-up.

Source: ENA

6.2 ToU and cost-reflective pricing

Efficient network pricing should provide pricing signals which reflect the long-run cost of capacity upgrades normally caused by the network demand peaks. These peaks often occur across a small number of periods during the coldest winter days.

ToU pricing plans can signal these busy network periods by having different prices for 'peak' times. However, because these prices apply to consumption across pre-defined time periods, the signals are usually 'softer' than, say, peak demand pricing. For example, a peak charge that applies across the time periods 7am-11am and 5pm-9pm for all weekdays includes 4,160 half hour periods (260 days and 16 half-hour periods per day). In contrast, a pricing construct that applies to the single highest half hour peak period would be an extremely sharp pricing signal.

A distributor can use ToU pricing to signal the network peak periods, while mitigating the potential for rate shocks that may result from a purer LRMC demand pricing option. Distributors can manage the strength of this peak signal through how they define the peak period, including the:

- length of the peak period
- number of months that peak charges apply
- price that is applied at the peak relative to other pricing components (if others are used).

Submissions received on the ENA's 2016 discussion paper indicated broad support for ToU pricing with general agreement across submitters that ToU pricing structures need to be simple as well as consistent between distributors.

6.3 Designing ToU consumption pricing

The key factors to consider in the design of a ToU pricing structure are:

- the timing of the peak periods
- the number of different ToU prices (peak / shoulder / off peak).

To design the ToU pricing structure that will result in more efficient network utilisation, a distributor must understand its existing load profile(s) and then consider how this load profile should or could change when consumers respond to the ToU pricing signals.

Design factor - review load profile

The timing and length of peak times can be designed using load profile analysis. Figure 21 shows an example of a network load profile, expressed as a percentage of the average load during the period, compared to the maximum demands each month. This example shows two 4-hour clusters of load during the morning and evening peak periods, from 7am-11am and 5pm-9pm.

Figure 21 Example of a distributor's load profile 'heat map'

Time period	Month												Average
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0:00	28%	28%	28%	26%	32%	34%	39%	37%	34%	33%	31%	30%	**32%**
0:30	27%	27%	26%	25%	30%	32%	37%	35%	32%	30%	29%	28%	**30%**
1:00	25%	25%	25%	24%	29%	31%	35%	33%	31%	29%	28%	27%	**28%**
1:30	24%	25%	24%	23%	28%	29%	34%	32%	29%	28%	27%	26%	**28%**
2:00	24%	24%	24%	23%	28%	29%	33%	32%	29%	27%	26%	25%	**27%**
2:30	23%	24%	24%	22%	27%	28%	32%	31%	28%	27%	26%	24%	**26%**
3:00	23%	23%	23%	22%	27%	28%	32%	31%	28%	27%	25%	24%	**26%**
3:30	23%	23%	23%	22%	27%	28%	32%	31%	28%	26%	25%	24%	**26%**
4:00	23%	24%	23%	22%	28%	28%	33%	31%	29%	27%	26%	24%	**27%**
4:30	23%	24%	24%	23%	29%	29%	34%	33%	30%	28%	26%	25%	**27%**
5:00	25%	26%	26%	25%	32%	32%	37%	36%	33%	30%	29%	27%	**30%**
5:30	27%	29%	30%	28%	37%	37%	42%	41%	38%	34%	33%	30%	**34%**
6:00	31%	35%	37%	34%	45%	45%	50%	50%	46%	41%	41%	34%	**41%**
6:30	34%	41%	43%	40%	54%	53%	59%	60%	54%	48%	47%	39%	**48%**
7:00	38%	46%	49%	44%	61%	61%	67%	68%	61%	54%	54%	44%	**54%**
7:30	41%	49%	52%	47%	64%	65%	72%	72%	64%	57%	57%	47%	**57%**
8:00	43%	49%	51%	47%	63%	64%	72%	71%	63%	58%	56%	49%	**57%**
8:30	44%	47%	49%	47%	59%	61%	69%	67%	60%	56%	54%	49%	**55%**
9:00	46%	47%	48%	45%	57%	59%	67%	64%	58%	55%	53%	49%	**54%**
9:30	46%	46%	47%	44%	55%	58%	64%	61%	56%	54%	52%	49%	**53%**
10:00	46%	46%	46%	43%	54%	56%	62%	59%	54%	53%	50%	48%	**51%**
10:30	46%	46%	45%	43%	53%	55%	61%	57%	53%	52%	50%	48%	**51%**
11:00	46%	46%	45%	42%	51%	54%	59%	55%	52%	51%	49%	47%	**50%**
11:30	45%	46%	45%	41%	50%	53%	58%	54%	51%	51%	49%	47%	**49%**
12:00	45%	45%	44%	41%	49%	53%	57%	53%	50%	50%	49%	46%	**48%**
12:30	45%	45%	44%	41%	49%	52%	56%	53%	50%	49%	48%	46%	**48%**
13:00	44%	45%	44%	40%	48%	52%	55%	52%	49%	48%	48%	45%	**48%**
13:30	44%	45%	43%	40%	48%	51%	54%	51%	48%	48%	47%	45%	**47%**
14:00	43%	44%	43%	40%	48%	50%	54%	51%	48%	47%	47%	44%	**47%**
14:30	43%	44%	43%	40%	47%	50%	53%	50%	48%	47%	47%	44%	**46%**
15:00	43%	44%	43%	40%	47%	50%	54%	50%	48%	46%	46%	44%	**46%**
15:30	43%	45%	44%	42%	49%	53%	56%	53%	50%	48%	48%	45%	**48%**
16:00	43%	46%	45%	44%	52%	56%	59%	56%	52%	49%	49%	45%	**50%**
16:30	44%	47%	47%	46%	55%	61%	64%	60%	55%	50%	50%	46%	**52%**
17:00	45%	48%	48%	48%	62%	69%	72%	65%	59%	53%	52%	47%	**56%**
17:30	47%	50%	50%	52%	71%	77%	81%	74%	64%	55%	54%	49%	**60%**
18:00	47%	50%	50%	57%	76%	79%	86%	82%	70%	57%	55%	50%	**63%**
18:30	48%	51%	51%	58%	76%	80%	88%	85%	75%	59%	56%	50%	**65%**
19:00	46%	49%	51%	56%	74%	77%	86%	84%	75%	60%	56%	49%	**64%**
19:30	45%	49%	53%	54%	71%	74%	83%	81%	73%	62%	56%	49%	**62%**
20:00	45%	49%	55%	52%	67%	70%	79%	77%	69%	62%	57%	48%	**61%**
20:30	46%	51%	53%	49%	64%	67%	76%	74%	66%	61%	58%	50%	**60%**
21:00	47%	50%	50%	46%	60%	63%	72%	70%	62%	58%	56%	50%	**57%**
21:30	46%	47%	47%	43%	56%	59%	67%	65%	58%	54%	53%	48%	**54%**
22:00	43%	43%	43%	39%	51%	53%	61%	58%	52%	50%	48%	45%	**49%**
22:30	39%	39%	38%	36%	45%	48%	54%	52%	47%	45%	43%	41%	**44%**
23:00	35%	35%	34%	32%	40%	42%	48%	46%	42%	40%	38%	37%	**39%**
23:30	32%	31%	31%	29%	36%	38%	43%	41%	37%	36%	34%	34%	**35%**
Average	**38%**	**40%**	**41%**	**39%**	**49%**	**52%**	**57%**	**55%**	**50%**	**46%**	**45%**	**41%**	**46%**

Source: ENA

Distributors should consider how these profiles vary across business days and at weekends in determining whether the peak period should cover business days only or be applied across all days of the week. The peak periods also have relevance in the design of network peak demand prices, which are discussed further in section 7.

Design factor - impact of load shifting

In setting peak periods, distributors should be mindful of the impact load shifting could potentially have on load profile, if the ToU pricing signals generate changes in the load profile.

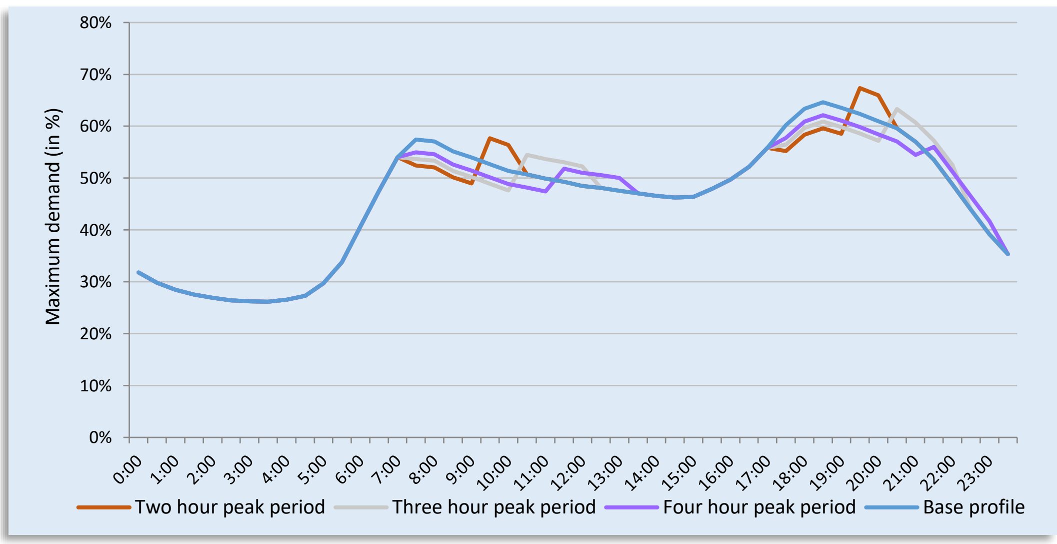
International studies show that ToU pricing can result in a 5-10 percent reduction in peak demand through a combination of load shedding and load shifting;

- load shedding is where consumers reduce their consumption in response to new prices
- load shifting is where consumers shift their consumption from peak periods to another time.[33]

ToU pricing could unintentionally create an artificial peak at the transition period between the original peak and off-peak time periods due to material load shifting. Some distributors have introduced a three-rate pricing plan with a shoulder period and smaller pricing differentials to lessen this risk.

Figure 22 shows an illustrative example of load shifting where the greatest impact is from setting relatively short ToU peak pricing periods. For this example, the steep existing peak periods (blue line), combined with a short two-hour peak ToU peak period, could effectively shift the load, and create a new peak between 7pm and 8pm (brown line). In contrast, a broader four-hour peak period such as from 5pm to 9pm still results in some load being shifted but is much less likely to create a new peak (purple line).

Figure 22: Estimate of the impact of load shifting



Source: ENA

Consumers may volunteer to reduce load, allowing distributors to use their existing load control differently. Shifting may also help offset any voluntarily restored load, meaning distributors could lengthen the peak period or use a shoulder period to dampen the incentive to restore full load at the end of the peak period. However, load profiles will be different across all distributors, and the impact should be individually assessed for 'best fit'.

[33] Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence Ahmad Faruqui and Sanem Sergici January 10, 2009.

Design factor - treatment of transmission charges

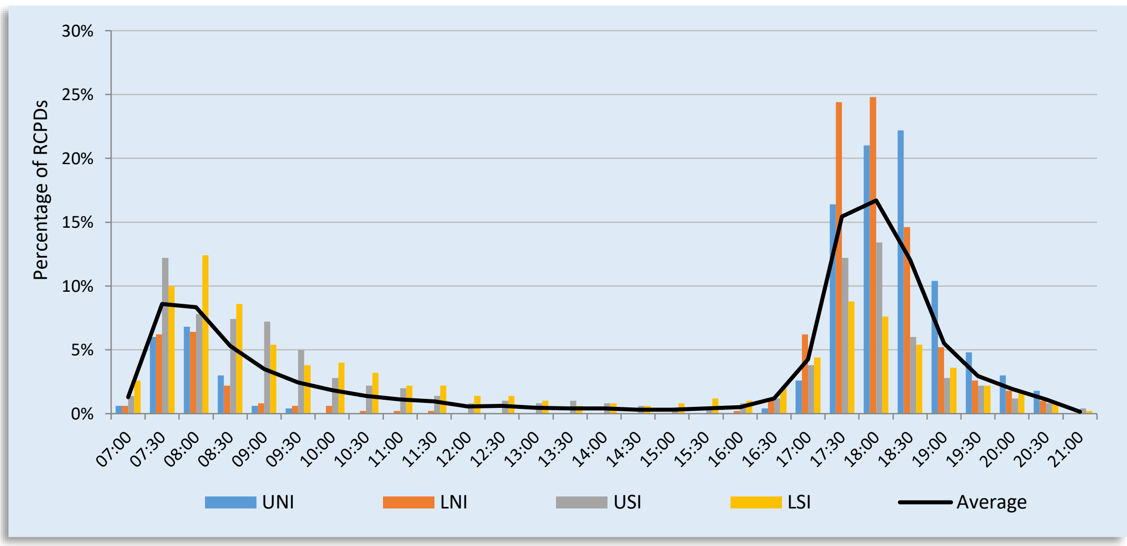
Another key consideration in designing any pricing plan, including ToU, is how to recover transmission costs. Transmission charges are a significant cost for all distributors, being on average around one quarter of their overall revenue requirement. Distributors should review how to recover these charges in the most cost-reflective manner, keeping in mind the potential impact on volumes due to behavioural change, technology uptake, and improved energy efficiency. The grid's regional coincident peak demand (RCPD) data can be grouped by region to analyse peak demand across days, month, and years, and days of the week.[34]

Transmission pricing

The Transmission Pricing Methodology (TPM) is currently under review and the way transmission charges are allocated and levied will likely change. The following section discusses one way in which distributors could pass these costs through, based on the existing methodology (RCPD) but the approach could be adapted to accommodate any new allocation methodology.

For simplicity, only the 100 highest RCPDs for each region are included.[35] Figure 23 shows that the timing of these peaks is strongly aligned across four regions: namely 7am – 9:30am and 5:30pm – 7:30pm. Figure 24 shows these peaks occur typically during three winter months (June – August), but can be longer in the Lower South Island region (LSI).[36]

Figure 23: Regional transmission peaks by time of day



Source: ENA analysis of Transpower data

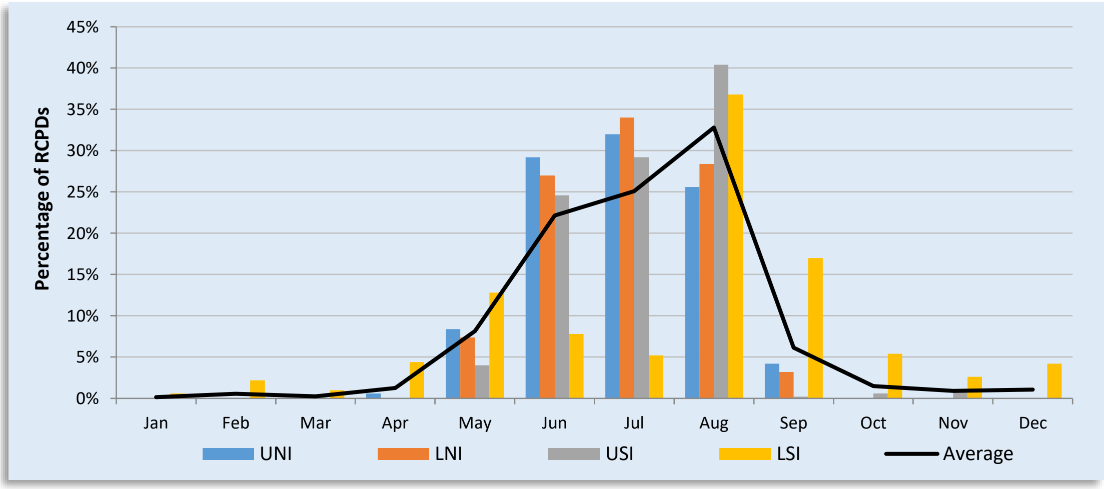
[34] Appendix B describes how the regional coincident peaks fall to different parts of NZ under the current TPM. These peaks drive a material portion of the EDB's costs.

[35] The peak periods were determined following the application of adjustments allowed under the Transmission Pricing Methodology (TPM) and are available at: www.transpower.co.nz.

[36] It is noted that the peaks in the LSI region are driven by a single end user (New Zealand Aluminium Smelters), which also results in LSI peaks outside the winter months.

Because the data suggests a strong correlation between transmission and distribution network peak demand periods, there is potential for a nation-wide template for ToU pricing periods. However, within this regional grouping there may be some distribution networks which have different peak times (for example, summer peaking networks). As discussed above, narrow peak periods may be susceptible to a shift in the peak rather than a smoothing effect of load.

Figure 24: Regional transmission peaks by month of year



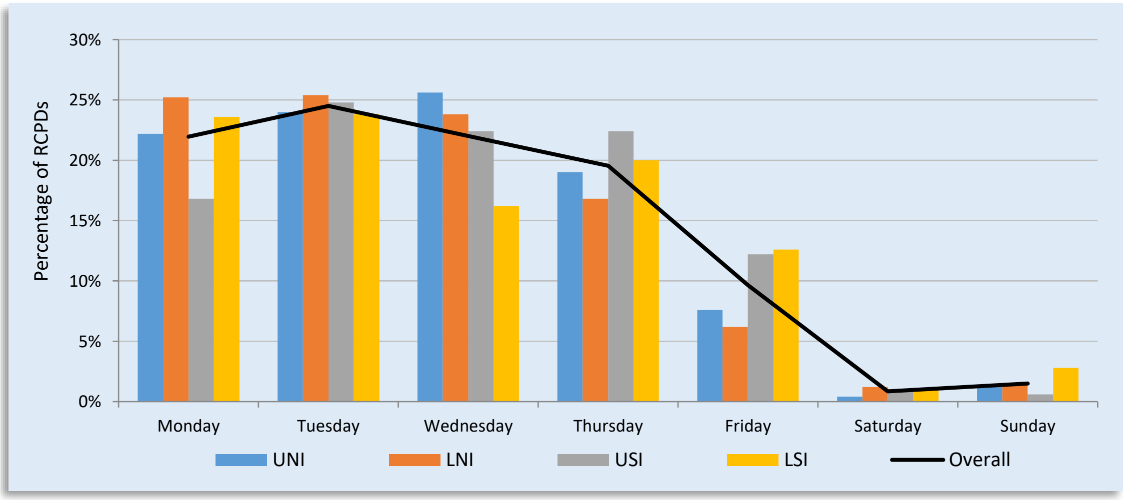
Source: ENA analysis of Transpower data

From Figure 25, it is evident that the:

- clear majority (more than 95%) of regional transmission peaks occurs during week days
- highest concentration of peaks occurs mid-week rather than Monday or Friday.

This analysis promotes the idea of a combination of "weekday/weekend" ToU consumption tariffs across all regions. This analysis could also be extended to include weekday public holidays but most distributors with existing ToU offers ignore public holidays for simplicity reasons.

Figure 25: Regional transmission peaks by day of week



UNI = Upper North Island, **LNI** = Lower North Island, **USI** = Upper South Island, **LSI** = Lower South Island

Source: ENA analysis of Transpower data

Design factor - two versus three rate plans

In developing a ToU-based pricing plan, distributors and retailers need to consider how they will define pricing. To align with costs, these prices will typically reflect the underlying cost drivers. Offsetting this cost reflectiveness goal is a desire among many consumers for simplicity, ease of understanding and transparency. This typically means that ToU-based pricing plans are defined into fewer rate groups. ToU-based pricing plans that are currently popular across the industry are two-rate and three-rate plans.

Two-rate plans typically consist of a peak price which applies only during a relatively short pre-defined peak period (excluding weekends) and an off-peak price which applies for all other times. A two-rate pricing plan is relatively simple to communicate to consumers. It requires fewer tariff codes and can provide peak pricing signals while allowing consumers to benefit from off-peak rates over longer periods.

Three-rate plans typically consist of a peak price, a shoulder price and an off-peak price. The peak price applies for a pre-defined period like the two-rate plan but is typically for a shorter period (say two hours instead of the typical four hours on a two-rate plan). The off-peak price usually applies over the 11pm-7am period (mirroring the historical ‘night’ charging period), while the shoulder price applies over remaining times.

From a consumer’s perspective, the shoulder price provides a transition between the higher peak price and the lower off-peak price. A three-rate plan is therefore better at providing very granular and well-defined pricing signals across multiple periods compared with a two-rate plan.

Three-rate plans allow distributors to provide a more structured set of prices delivering greater levels of incentive for consumption during the off-peak period, as well as providing incentives for consumption outside of the peak periods. When combined with appropriate price differentials, the shoulder period also helps to dampen the incentive for load shifting while enabling a narrower, stronger, price signal through the peak period.

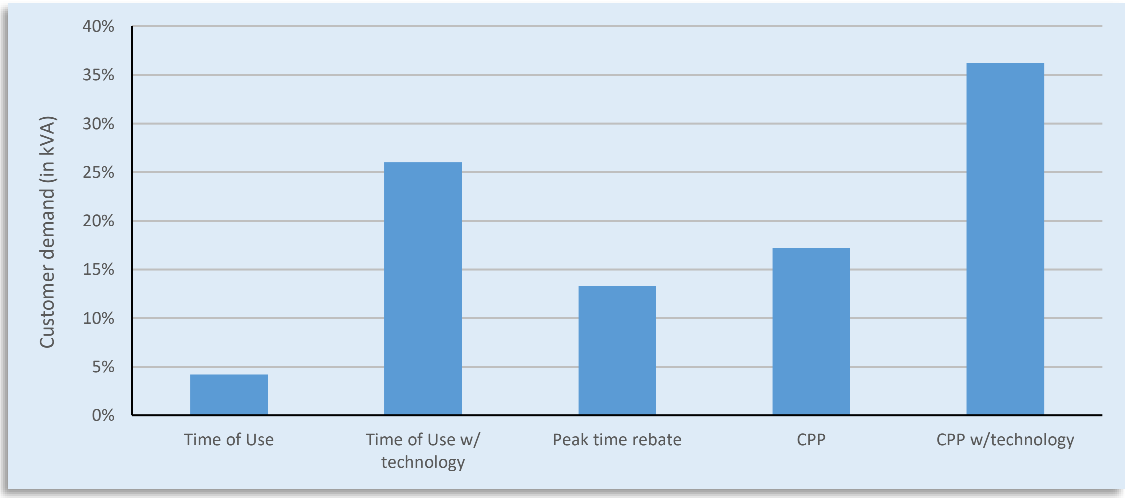
In the submissions received during the ENA consultation process there was no strong consensus on the preferred number of ToU rates or whether the peak period should only apply on weekdays during defined peak months. Instead, submitters commented that the definition should depend on the distributor and reflect the characteristics of their network.

6.4 International experience

The ENA’s *More Cost-reflective Pricing* guidelines (MCRP) from October 2011 provide a useful summary of international trials and deployments of advanced tariffs across different markets. The report notes that it can be difficult to take international learnings and directly translate them into New Zealand conditions. The following chart from this report shows that different pricing plans do impact peak demand, with ToU pricing at the lower end of the scale, probably due to the longer ToU peak demand signal. ToU pricing should therefore be considered by distributors that are not necessarily capacity constrained but seeking a more cost-reflective price structure, or consider that there are benefits to shaping consumer behaviour to avoid future network congestion during peak times.

The chart also suggests that “technology” such as in-home displays (“IHDs”) plays an important role in achieving material peak reductions, regardless of the pricing approach. Critical peak pricing (with technology) generates the strongest peak demand response, with average peak reductions of 35 percent.

Figure 26: Peak Reduction by Rate and Technology



Source: Grattan Institute 2014 (page 25)

Chart notes: ToU is a time of use pricing trial; "w/technology" is a trial involving consumers being provided with technology to assist in energy management, including in-home display units or technologies to actively manage energy consumption (eg; smart thermostats); Peak time rebate is a system where rebates are paid for demand reductions below an agreed baseline; CPP is critical peak pricing where on a certain number of pre-determined days the electricity supplier may call a critical peak, where rates during peak periods are several multiples of normal unit rates (eg, $1 per kWh, or more).

6.5 Other considerations

Price levels

Inducing a behavioural response from ToU pricing depends on the number of consumers on these pricing plans (at a macro level), consumers' ability and willingness to respond, and the pricing differentials between peak and shoulder or off-peak prices (at a micro level).

The difference in price between the peak-off-peak demand periods needs to be large enough to signal the economic cost of providing supply during peak times (financial incentives need to be material for the consumer), while being mindful of the distribution of consumer impacts associated with the new pricing plan. While the peak price will be dependent on the individual characteristics of the network, research suggests that a retail 'peak price' that is three to eight times the standard retail price of electricity is likely to elicit a consumer behavioural response.[37]

Seasonality

Another important element to consider when developing a ToU pricing plan is the months or seasons that peak demands are occurring.

[37] Grattan Institute 2014 (page 25)

Distributors with existing ToU pricing plans have preferred the simplicity of a non-seasonal ToU pricing plan as these are easier to communicate to the consumer and have less potential for adverse bill shocks. That said, seasonal ToU pricing plans have the potential to be more cost-reflective and provide stronger pricing signals than non-seasonal ToU pricing plans.

Figure 24 illustrates where a seasonal ToU pricing plan could be considered due to the strength of the network peaks over winter months May-September.[38]

Load control (and other metering types of pricing)

Most distributors can remotely control a portion of a consumer's load that is connected to a ripple relay on the metering board (as discussed in section 4.1). This is typically a hot water cylinder but can be other forms of non-critical load. This allows distributors to manage a portion of their peak demand to optimise their load profile, better manage outages and potentially defer future investment. Most distributors offer a discount in their pricing to incentivise consumers to maintain controllable load and as a reward for the potential inconvenience of an interrupted supply.

It is recommended that if distributors introduce a ToU pricing plan (or any other pricing plan) that consumers continue to be offered an appropriate incentive to provide their controllable load to the distributor and that the distributor's ability to utilise this load is not inadvertently diminished through the introduction of new pricing.

When setting prices for peak, off-peak, shoulder (if applicable) and controlled load pricing it is important for distributors to consider the implications for consumer incentives to opt for load control, as compared with the potential to switch off hot water heating during peak periods.

Metering

Because ToU pricing relies on the accurate and timely provision of metering data to retailers and distributors, the capability of metering infrastructure at the consumer's premise will dictate the availability of advanced types of pricing.

In the absence of advanced metering, a distributor could profile a consumer's consumption to generate an estimate for the relevant ToU-based prices. This is however not recommended.

An alternative approach to profiling would be to determine the overall costs based on the ToU prices for a typical customer and determine an equivalent flat volume-based charge by dividing the total costs by the total consumption. Therefore, consumers without advanced metering would still face the same overall costs as those with an advanced meter but would be charged a simple flat (or non-ToU) price. A consideration is that this can create an arbitrage opportunity for those with costly load profiles to shelter from high charges.

[38] In practice, a seasonal ToU pricing plan could apply for both two and three rate plans. A two-rate plan may simply have a much higher "peak price" over the winter months compared to the summer months while a three-rate plan may choose to have the "peak price" to be equal to the "shoulder price" over the summer months but increase to a much higher price over the winter months.

Billing systems and information exchange

Distributors who cannot directly access metering information need to consider how to receive relevant data from retailers so they can bill ToU prices.

Currently retailers use a file format developed specifically for legacy meters, resulting in limited ability to use these files for half hourly data from advanced meters. Similarly, the file format that retailers currently use to exchange half hourly information for category 3 sites has not been designed to accommodate mass-market information. Distributors wanting to receive half hourly information from retailers will therefore need to talk to retailers on their network and arrange a suitable file exchange format and process.

If distributors only require the quantities for the pre-defined ToU periods, then it is possible to utilise the existing file format by requesting retailers to aggregate the half hourly data into the relevant periods and submitting the quantities under the relevant tariff code.

Consumer impacts

Shifting from a flat consumption-based price to ToU-based pricing will typically have the smallest impact on consumers, compared to other types of pricing, due to the continuation of the kWh basis for charging. The range of consumer impacts will be directly related to the size of the pricing differentials between the peak and off-peak price component. Distributors should set the pricing range with the potential impacts in mind. As discussed in more detail in section 11, there are several transition strategies that can be used to manage consumer impacts.

Advantages and disadvantages

Figure 27: Advantages and disadvantages

Advantages	Disadvantages
ToU pricing is more cost-reflective than existing volume based types of pricing by signalling periods when network peaks are most likely to occur.	ToU pricing is not as cost-reflective or service-based as other advanced types of pricing and typically spreads the peak pricing signal over many peak period hours.
ToU pricing is just as compliant with existing LFC regulations as legacy pricing.	May not be durable as batteries become cheaper. May encourage premature investment in batteries on some networks.
Retailers have expressed strong support for ToU pricing over other advanced types of pricing.	Strong self-selection bias under an ‘opt-in’ approach.
ToU pricing is relatively easy to communicate to consumers and is more predictable than other advanced types of pricing.	Potential revenue at risk resulting from behavioural change and/or ‘cherry picking’ by retailers.

Source: ENA

Options for alignment

As at July 2017, seven distributors (who provide line services to some 43 percent of consumers in New Zealand) have some form of ToU plans in place, with some having had ToU pricing plans since 2010.[39] These existing ToU plans have similar structures and peak period definitions (see Appendix A for an overview of existing plans).

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.

The following figure 29 sets out a peak/off-peak rate pricing option for ToU alignment, and an alternative that incorporates a shoulder period. These are both based on ToU pricing that is currently offered by distributors.

Figure 28: ToU consumption template option

PRICE OPTION **Simple definition**	**TIME OF USE** ***$/kWh price varies with time of day***
Detailed definition	Pricing based on consumption (kWh) which varies with the time of day and day of year, with 'peak' price periods set higher than 'off peak' periods. Peak periods are pre-defined and set regarding when load on the network is highest. Consumer is rewarded by lowering or shifting usage outside of peak times.
Peak definition	• Weekday peak • Morning 7-11am, evening 5-9pm • No shoulder period
Unit of measure	kWh
Alternative peak definition	• Peak: 7am-9:30am, 5:30pm-8pm, Shoulder: 9:30am-5:30pm, 8pm-10pm • Workday peak, excluding public holidays

Submitters on the discussion paper were generally supportive of the ToU template detailed above with submitters commenting that it should enable greater consistency between distributors. Two retailers suggested slightly different definitions for the template which provided differing levels of pricing signals. But due to the broad support for the existing template, and the fact that variations will naturally occur as distributors consult and engage with their stakeholders, ENA chose to maintain the existing definitions within the template.

[39] Excluding GXP based ToU-based pricing methodologies.

7 Demand Pricing

Demand prices relate to the electrical load at an individual consumer's connection. Compared to other pricing methods, demand pricing can provide more cost-reflective signals and a fairer means of recovering fixed costs, as well as effectively signalling future capacity constraints in the network. However, there are practical complexities with implementation, including the need for significant education of consumers. We have identified two demand pricing approaches:

1. Customer Peak Demand:

- measures the maximum load of the connection at any time
- is more appropriate for recovery of cost related to assets that are closest to the consumer (such as costs of the low voltage network)
- may be used to recover a distributor's fixed costs that are not fully recovered through fixed charges.

2. Network Peak Demand:

- measures the load of the connection during the network's busy hours
- is a congestion charge and more appropriate for signalling to consumers the potential for capacity up-grades
- is more appropriate for recovery of cost related to assets associated with the high-voltage network.

There are different benefits from, and reasons for, using either customer or network peak demand. Both can be used on their own or in combination with other pricing components.

7.1 Customer Peak Demand Pricing

Customer peak demand pricing is service-based because it reflects the capacity that individual consumers demand. Customer peak demand pricing enables active consumers to contribute to fixed costs, while rewarding those who can limit the load they put on the network. Prices would be based on customer peak demand, measured in kW over a given period (for example, one month or one year).[40]

Definition

Customer peak demand based prices are applied to a consumer's maximum demand at any time. These are often referred to as Anytime Maximum Demand (AMD) prices.

[40] Strictly speaking the use of kVA is a more accurate measurement, however kW is considered more appropriate for general consumer because it is easier to understand and is more likely to be measured through metering at consumers' premises.

Current experience

Customer peak demand pricing is primarily used by distributors across New Zealand for large commercial consumers. While there are four distributors in New Zealand who use demand pricing for residential and smaller business consumers, only one uses customer peak demand charges, as per the following:

Distributor	Methodology basis	Type of demand price
Aurora	ICP level demand charge	Network Peak Demand
Orion	GXP based demand charge	Network Peak Demand
Powerco (Western Region)	GXP based demand charge	Network Peak Demand
The Lines Company	ICP level demand charge and capacity charges	Customer Peak Demand and Network Peak Demand

Designing a Customer Peak Demand Methodology

Key factors that need consideration when designing customer peak demand pricing are:

- how often the level of demand is reset
- how many demand measurements are made during the measurement period
- the duration of the measurement period
- whether controlled load is included
- whether any periods are excluded
- units of measurement.

These factors are common across types of pricing and variations of demand based pricing.

Demand reset period

This is probably the most important factor. Customer peak demand can be measured, and reset, on any defined period with the most obvious being monthly or annual resets. Annual measurement is the most cost reflective because it is based on the consumer’s highest demand during the year, which is a more relevant cost driver than demand during a shorter period such as one month.

Residential consumers may, however, find an annual measurement difficult to work with. Monthly measurement gives consumers an immediacy of their network demand as well as a sense of control over their electricity bill, rather than being required to pay on a measurement made up to 12 months prior. A monthly measurement reset would also reduce the issues associated with consumers moving premises and reduce the need for default consumer demand profiles for new consumers.

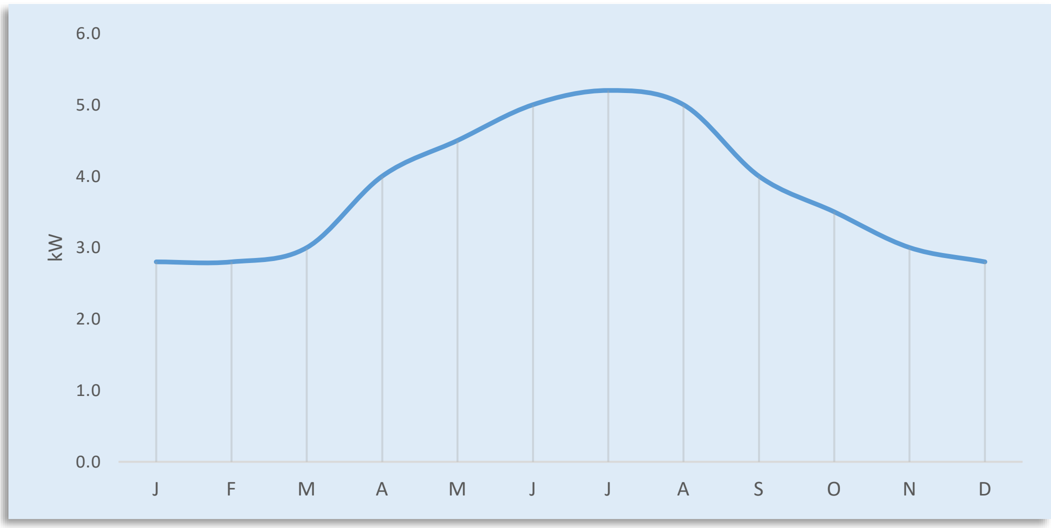
An alternative may be a 12 or 13 month rolling average reset which has less lag between usage and measurement. Here, customer demand is measured and updated monthly and then averaged over the previous 12 or 13 months. This approach does have administrative issues for retailers to deal with. In addition, the coincidence of an early winter followed by a late winter could result in under-recovery of costs.

The choice of which period to use may be influenced by the consumer's demand profile. The demand profile of individual consumers will vary throughout a year, with some having a higher demand in one season than another. For example:

- irrigators have high use during dry summer months but little use at other times
- holiday homes/accommodation businesses primarily used in winter months may have low/zero loads during summer periods, but high loads in winter. The opposite is true for summer-based businesses and holiday homes
- dairy sheds may typically operate from June until March with high, flat loads, but zero loads during other times.

A typical residential household may have a profile such as that in Figure 29, which shows highest demand in winter months.

Figure 29: Example of residential consumer demand by month



Source: ENA

Because of these seasonal variations, an annual reset of Customer peak demand measurement is likely to be more cost-reflective, and result in all consumers paying a fair share of costs, than a monthly reset period. Distribution networks that have consumers with strong seasonal demand may receive little contribution to fixed or sunk costs for some of the year when using a monthly reset. Among the parties submitting on the consultation paper who supported customer demand there was a slight preference for monthly resets. However, in a later question about network demand there appeared to be a clearer preference for annual resets.

The choice of the demand reset period depends on the mix of prices that a distributor uses. If customer peak demand pricing is the only price component, a shorter reset period may be appropriate. If it is used in combination with other pricing components, then a longer period may be more suitable.

How many measurement periods and how long?

The measurement period is also important. The true capacity required by a consumer is the single highest demand peak over the measurement period. This event can be derived from smart meters which provide energy consumption data in half-hour intervals. If demand is measured monthly, a single half hour measurement may be acceptable because it accurately records the month-by-month demand variations.[41]

If demand is measured annually, a greater number of peaks are needed to reduce the impact of a single high demand event impacting the consumer's bill for the remainder of the year. A greater number of peaks may also better reflect the impact of consumer demand on network assets. For example, transformers can be overloaded for short periods with no adverse effects but extended overloading may require them to be upgraded.

Treatment of controlled load

Another consideration for distributors is whether controlled load should be included in the measurement of demand. This is because load control periods may directly impact a consumer's maximum demand. For example, at the end of a controlled period, a customer demand peak may be created as the hot water (and other appliances) are switched back on.

If meter capability permits, demand could be measured excluding controlled load. Alternatively, the highest peak after a load control period could be ignored, reading from the second (or third or fourth) highest peaks. Individual distributor circumstances will influence this decision.

Units of measurement

Although kVA is the true measure of demand capacity, for simplicity reasons we recommend the use of kW for residential consumers. Consumers are more likely to be familiar with the term kW (for example, 2kW heaters) whereas kVA would be a new concept to most residential consumers.

International experience

Customer peak demand pricing is not widely used in mass market situations. This type of pricing has been trialled in several smaller locations. Australia has consulted on and begun to implement a range of demand-based methodologies while in the US, customer peak demand pricing has been used by Black Hills Power in South Dakota where distribution pricing is measured on a consumer's monthly non-coincident peak.[42] Non-coincident peak demand has also been used in several other North American situations.

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[41] Consultation undertaken in Australia indicates that consumers favour simpler pricing with a short measurement period. Outcomes from the Australian consultation processes do, however, need to be treated with a degree of caution. This is because cost-reflective pricing has yet to take effect and therefore any consumer comments are based on hypothetical scenarios rather than actual experience.

[42] A Review of Alternative Rate Design Rocky Mountain Institute. James Sherwood *et al* page 50

Figure 30: Advantages and disadvantages

	Advantages	Disadvantages
Annual customer demand pricing	Provides a fair recovery of fixed and sunk costs that are unrecovered through fixed charges More stable bills for both consumers and networks over the year Better incentives for managing load by using in-house technology Prices better reflect costs of network investment. The more capacity required, the greater the network charges.	Depending on number of peaks, can deliver a sharp signal. Can have large bill impact Rewards from reducing demand are not immediate New concept for consumers Administrative issues
Monthly customer demand pricing	More cost-reflective than consumption pricing Immediate reward for consumer from reducing load Less consumer impact than annual customer demand pricing Easier to apply for connection changes than annual demand pricing (ie, only requires a default profile for one month)	Less reflective of overall capacity requirements than annual pricing Recovery of fixed costs not as fair as annual demand measurement (especially where there is a significant number of seasonal connections) Retailers may require estimates depending on data availability Higher winter bills for consumers than annual demand pricing

Source: ENA

Options for alignment

The following customer peak demand pricing template is proposed as an option for alignment across distributors.

An annual measurement has been selected as it is most cost-reflective. There is an implicit assumption in the make-up of the template that customer peak demand would be only one component of the network price. For example, a distributor may combine a customer peak demand price with ToU or network peak demand pricing.

Figure 31: Customer peak demand template option

PRICE OPTION Simple definition	CUSTOMER PEAK DEMAND (Anytime Maximum Demand) ***$/kW Price based on actual maximum demand over 12 months***
Detailed definition	Pricing based on measured maximum demand. Consumer is rewarded for managing their load.
Unit of measure	kW
Period of measure	Annual measurement. Number of half hours to be determined by distributor.
Example	$0.20/kW/day
Default	Profile
Alternative price structure	Monthly

7.2 Network Peak Demand Pricing

Network peak demand pricing has a lot in common with customer peak demand, except that prices are based on the network demand peaks rather than the demand peaks of individual connections. The two may not coincide for individual consumers or for groups of consumers.

Distributors build their networks to cater for the accumulation of maximum demand loads that occur on the network. A network peak demand approach applies a price to a consumer's load during the periods when a network peak occurs. Reflecting network peak demand costs in electricity prices lets consumers choose when it is cost-effective to use electricity. Many uses of electricity can be delayed or timed to avoid network peaks, which makes it somewhat discretionary. For example, consumers can choose when to make use of a clothes dryer, the heating on a spa pool, a dishwasher, or when to charge an electric vehicle.

Outside of these network peak periods, the system is underutilised, which provides distributors with an opportunity to improve network efficiency. The intent is to encourage consumers to reduce and/or shift their ***discretionary*** load from times when the distributor's network is near full capacity. This is expected to avoid or defer future network investment, which will result in lower prices in the future.

Definition

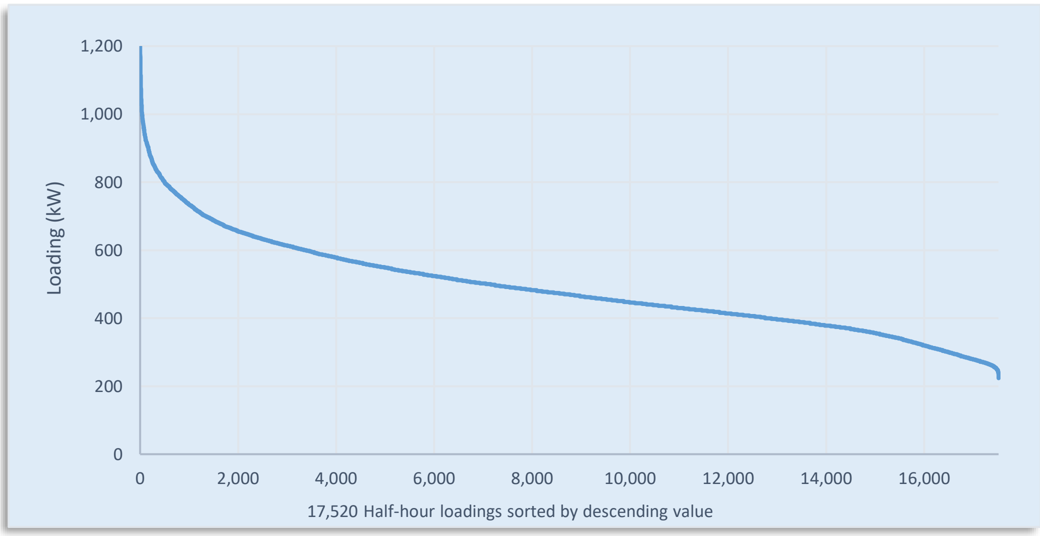
A network peak demand quantity, in kilowatts (kW), measures a consumer's load during network peaks. Network peak demand prices are applied to the demand during periods when a network system peak occurs, or is likely to occur. It is also referred to as a co-incident maximum demand (CMD) and is considered the most cost-reflective option in these guidelines. Submitters who supported demand pricing preferred network demand, because it was the most cost reflective.

Network peak demand pricing is however more complex to develop and implement, requiring a good understanding of both demand on the network and how consumers use the network over time.

The nature of system peaks

Consider a load duration curve (where loadings are stacked up, highest to lowest) in Figure 32 below which provides an example of a load duration curve for a New Zealand distributor. The left-hand side of a load duration curve, the tall peak, provides the best opportunity for savings. Here, load reductions are only required for a very short period to reduce peak load and save costs. The flatter part of the load duration curve is less suited to peak pricing because reductions in network demand are required over a much longer period.

Figure 32: Annual load duration curve – example for a winter peaking network



Source: ENA

In this example, consumers only need to respond for a total of 100 half-hour periods to reduce the peak load by 278 kW – that is a large 23 percent reduction in peak load for a reduction over just 0.6 percent of the time.

Current experience

Network demand methodologies have been used for pricing to large commercial and industrial consumers in New Zealand for some years. Different forms have also been implemented by some distributors (Aurora, Orion, Powerco and The Lines Company) for residential and/or small business consumers. Boxes 2 and 3 show examples of dynamic peak demand pricing implemented by The Lines Company (TLC), Orion, and Aurora.

Box 2: TLC Peak Demand Pricing[43]

TLC Network Peak Demand Pricing (kW load)

- kW load measured using advanced meters at times when TLC is load controlling
- price is applied to the customer's average load during the six highest 2-hour peaks
- the average kW load of a TLC customer is 2.65kW
- the quantity is measured from the previous year and applied to customer's invoices from 1 April
- the invoices are sent to customers directly and remain the same from 1 April to 31 March

Example of pricing (high density/low voltage in Hangatiki region)

		Quantity	Units	Price	Charge
Capacity charge		5	kVA	$4.18	$20.90
Network demand charge	Distribution	2.65	kW	$18.55	$49.16
	Transmission	2.65	kW	$6.84	$18.13
Relay charge		1		$1.72	$1.72
Meter charge		1		$5.43	$5.43
Total (ex GST)					**$95.34**

Box 3: Orion Network Peak Demand Pricing

The Orion peak charge is based on average real power loading during the chargeable peak period. Peak periods occur when consumption would exceed predetermined triggers if Orion did not load control. The trigger points are adjusted so that Orion accumulates between 100 and 150 hours of signalled peak periods aimed at the highest loading periods during the winter season. The peak is signalled to customers using ripple signals, email, messages, and is displayed on a website dashboard. Consumers can elect to reduce their exposure to the peak period charge by reducing their load.

Peak period loadings are not known at the start of each financial year. To overcome this, Orion relies on an estimate based on final peak periods for previous years. Delivery charges are billed using the estimate during April to September. The first set of consumption data for the winter peak period season is available from the reconciliation manager from October each year. This data is used to calculate interim wash-up figures. Retailers are charged using this interim wash-up from October to April and the final wash-up is calculated the following April.

General connection peak price 53.25 c/kW/day

Volume price:

Weekdays (Monday – Friday 7am–9pm) 8.642 c/kWh

Nights and weekends 1.106c/kWh

Low power factor charge 20c/kVar/day

[43] Appendix E of this guidance paper presents a summary and analysis of the TLC experience to date with demand pricing and their decision to revert to a ToU pricing structure in place of the network demand. A TLC representative has been involved in the preparation of this guidance document and has shared the TLC experiences.

Box 4: Aurora Network Peak Demand Pricing

The Control Period Demand (CPD) price is the energy used at the installation when Aurora is managing demand. This energy usage will accumulate and at the end of the control period, the duration of the control period then divides the sum of the energy, to obtain average power demand.

The CPD for each installation is set at 1 April to the average of CPD kW (previous winter) and chargeable CPD kW (at 1 April previous year). The control period is likely to occur on cold winter days, anytime between 7.30 am and 10.00 pm, and to last typically for two to three hours (but could last for up to ten hours on occasions) and is most likely to occur on approximately 20 to 50 days during the May to September period with most activity during June, July and August. Control periods are signalled via ripple control and consumers may use this signal, via clean relay contacts, to operate a warning device to directly control deferrable load or to start up a standby generator, whichever is the most convenient. Notifications are also made by email, and/or text message, to registered consumers.

Where it is not presently economic to install control period demand metering for connections such as Load Group 1 (15kVA) and 2 (16-149kVA), then any charges that would normally be recovered via a control period demand price will be recovered via an effective control period demand charge based upon kWh consumption at the installation during winter. This will be based upon the four months consumption reported by electricity retailers for the period May to August. Controllable loads are encouraged by “discounting” the controlled load in the CPD calculation. This varies between 100% (for night loads) to 20% (All Inclusive Day loads). Uncontrolled load receives no discount.

The effective control period demand for each installation is set at 1 April to the average of CPD kW (previous winter) and chargeable CPD kW (at 1 April previous year). If a consumer commences during the year (ie. a new connection) a default control period demand will apply until a full winter is completed.

It is noted that at the time of finalising this report The Lines Company board had released a report advising that TLC would be transitioning away from demand pricing for residential and small business/commercial customers, replacing the demand based methodology with the Time-of-use pricing approach (see Appendix E for a summary of the findings of a pricing review commissioned by TLC). The EA has conducted a separate review of TLC’s pricing – see Box 5 below.

Box 5: EA review of TLC load control and pricing practices

The Electricity Authority announced in August 2016 that it would review the load control and pricing practices of The Lines Company (TLC), focusing on the interaction between those practices, the incentives they place on consumers and the outcomes they influence. The Authority reported on its review on 30 May 2017.

In their review, the Authority identified the following lessons. They are relevant to both demand pricing options as well as to broader implementation of pricing reform.

- *Linking distribution pricing with load controlling activity can cause unnecessary confusion and stress for consumers. The current transmission pricing methodology exacerbates these effects, and TLC's processes for determining when load controlling would reduce its transmission charges.*
- *Distributors need to carefully consider the range of systems needed to successfully implement any proposed pricing approach, from metering through to customer information technologies.*
- *Distribution pricing approaches that involve long delays between consumers' actions and the pricing impacts on them, or involve uncertainty for consumers about the timing of pricing rate changes, are likely to result in significant consumer stress.*
- *Implementing a new distribution pricing approach is a complex process and should be given an appropriate level of resource by distributors.*
- *Distributors and retailers need to ensure that pricing for consumers is understandable. Consumers must be able to evaluate the impact that investments or behaviour changes will have on their charges.*
- *Distributors should recognise that consumers are used to having choices. Pricing regimes that don't allow consumers to 'opt-in' or 'opt-out' need to be carefully introduced, preferably in a phased manner.*
- *Distributors should have monitoring systems in place to ensure that distribution pricing signals are working as intended and allow early intervention if changes are required.*
- *Distributors should remain responsive to feedback from consumers and retailers regarding the implementation of a revised pricing methodology, and should communicate their experiences to other distributors*

Designing a Network Peak Demand price

The design of network peak demand pricing needs to reflect the nature of the charge – that is, will it reflect the dynamic nature of network demand, or will the pricing approach be fixed to a static measure of network demand?

- A dynamic peak network demand price is applied during actual system peaks
- A fixed period network demand price has predetermined peak periods during which the consumer's demand is measured.

We look at design factors that are shared across these two approaches as well as those that are particular to dynamic and fixed pricing.

Among submissions on the discussion paper, only one submitter favoured dynamic peak pricing because it was more cost reflective. The remaining submitters who supported network demand favoured fixed peaks for mass market customers because it was simpler to communicate and implement.

Design factor - what measurement period

A common measurement period for demand pricing is a half hour. In the same manner, as for customer demand, the number of measurement periods will depend on whether the reset of demand measurement occurs monthly or annually. See section 7.1 for a discussion on the issues around the choice of measurement periods. As with customer demand, submitters generally favoured annual resets because they could be considered more cost reflective with only one of the seven submitters commenting on the frequency of resets expressing a preference for monthly resets. Another submitter raised the difficulties posed by annual or monthly resets for customers switching retailers.

Designing dynamic peak demand

Applied during actual system peaks, this type of charge focuses consumers' incentives to restrict load but only during periods when the network is constrained. However, consumers may not know when these peaks are occurring until after the event. The use of technology allows for better notification to consumers and provides more predictability.[44] Submitters noted that dynamic peak demand would require some form of signalling to consumers for it to work effectively.

Design Factor - how to define a network peak?

One approach to identifying network peaks is to specify actual network peaks over a certain threshold. This is the approach employed by Orion – box 3 above.[45] Another option is to define system peaks as only those periods when the network is using load control, as is done by TLC – box 2 above.

Design Factor - how many peaks?

Pricing could be applied to the consumer's average demand across all the identified peaks, or limited to the consumer's highest readings within those periods. Orion does the former while TLC does the latter. TLC applies the network demand charge to the six highest 2-hour periods during which it is load controlling.

Taking only a small number of the consumer's highest load measurements during the system peak periods is simpler than taking an average of, say, 100 peaks or more. However, taking fewer peaks may result in more volatile price signals to consumers. The amount of variation in consumer demand from period to period and the degree to which the network is close to being constrained are just two factors that will influence the number of peaks.

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[44] ***Critical peak pricing*** is a form of dynamic peak network demand pricing. It is a peak pricing methodology where the distributor signals, in advance, a system peak. Overseas implementation has seen critical peak pricing used in conjunction with rebates or technology. Critical peak pricing is not considered in detail in these guidelines, but may be an option for distributors. Because most New Zealand distributors are winter peaking, those peaks are highly weather dependent. The nature of New Zealand's climate makes accurate weather forecasting difficult and a distributor using critical peak pricing will face the risk of mis-signalling peaks.

[45] Orion calculates what load would have been if load control wasn't used. It does this by adding back the base load of water heaters that are turned off, and subtracting the difference between base load and nominal load of water heaters that have recently been turned on. This is used to trigger peak periods.

Design factor – refinements to dynamic network demand charge

An option is to refine the structure of the dynamic peak network demand methodology so that it is more attractive to end consumers and, thus, more likely to be passed through by retailers. Examples of ways to do this include the following:

- acknowledging that consumers could better respond with notice. It might be that the best a distributor can currently offer is real-time notification of when peak periods begin and end, but other opportunities to advise consumers are becoming available.
- restrict the times that peak periods can be signalled without disadvantaging the operation of a peak pricing arrangement. This can significantly enhance the response, providing certainty for consumers, and providing the option to permanently shift load outside the peak periods (rather than responding in real time). The Victorian distributors have adopted a peak that is defined by both season and time periods to give consumers an element of certainty.

Designing fixed peak demand

Because the peak periods are pre-defined, consumers have greater clarity as to when their demand will be measured, compared to a dynamic peak structure. This means that consumers can plan to avoid peak periods. This type of pricing is more likely to be understood by consumers and may be more likely to be passed on by retailers. There are, however, issues with this approach that impact the design of the pricing structure.[46]

Design Factor - what measurement period?

The issues to consider in determining the fixed peak demand periods are the same as for ToU pricing, that is:

- defining times when network system peaks are most likely to occur
- assessing whether the peak period will result in shifting of the peak
- assessing the risk that consumers will engage in uneconomic bypass activities.

Design Factor - network characteristics

A network demand charge is appropriate where the network is congested or has load growth. Network demand pricing can also be used to signal that future congestion may occur. For example, charging electric vehicles (EVs) could cause constraints on a network that previously had available capacity.

Design Factor - price signals

The effectiveness of a network demand price will depend on the strength of the price signal and how well consumers respond to it. Consumers will vary in their ability and willingness to shift and or reduce their load during peak network demand periods. Some will reduce or shift loads such as hot water, charging devices,

[46] For example, the fixed periods are aligned with the distributor's historical system peak periods, but there is potential for misalignment between the actual distributor peaks and time periods for the demand charge. This means that fixed period network demand is less cost-reflective than dynamic peak network demand pricing, however fixed period network demand pricing could be implemented as a transition toward a dynamic period network pricing structure.

dryers, dishwashers, and the like. Others have different preferences and may not want to manage appliances within their house. They may be happy to use more and pay more. The price itself needs to recognise the range of preferences and possible outcomes.

Other considerations

Meter data is critical to any demand price. If a distributor does not have access to meter data, it will need to rely on profiling, which brings difficulties to the price setting and billing process.

Consumer engagement and education is important, given demand pricing is a significant departure from current pricing. Communication with consumers will assist them in understanding the benefits of change. Some consumers will be negatively impacted by demand charging. These consumers will require assistance before, during and after implementation, including advice on how to reduce their demand profile and minimise the impact of the new charges. This could include in-home demand management tools and general education around usage of appliances. At the most basic level, customers will need information about peaks. This information must be timely and in a form that can be acted upon. It is likely that distributors will need to use a number of methods for engagement as customer's need for engagement will vary widely.

The provision of information and tools will need to be resolved between retailers and distributors, as several retailers view this as part of the retailer's function.

International experience

Internationally there is a growing trend towards network demand pricing. Several Australian distributors are in the early stages of implementation and transition. Figure 33 shows that Australian distributors have generally opted for fixed period network demand charges for residential consumers.

Figure 33: Summary of Australian network peak demand charges

Region	Electricity Distributor	Peak Demand Definition
ACT	ActewAGL	Maximum demand in the billing period
NSW	Endeavour Energy	NA
	Essential Energy	Based on the highest measured 30-minute kVA demand registered in each of the peak, shoulder and off-peak periods during each month.
	Ausgrid	NA
Queensland	Energex	Measured over a 30-minute period during peak hours.
	Ergon Energy	Measured over a 30-minute period in the monthly billing period. It applies to the customer's actual demand above a set threshold, which varies depending on the type of tariff.
Victoria	Citipower	**Residential:** Measured over a 30-minute period during the peak hours. **Commercial:** Measured on a 12-month rolling basis over a 15-30-minute period, calculated monthly.

	Jemena	**Residential:** Measured during the peak hours. **Commercial:** Consumers may be subject to a minimum chargeable demand level.
	Powercor Australia	**Residential:** Measured over a 30-minute period during the peak hours. **Commercial:** Measured on a 12-month rolling basis over a 15-30-minute period, calculated monthly.
	United Energy	Measured monthly over the peak period, subject to a minimum demand charge.
	AusNet Services	**Residential:** Measured over a 30-minute period during the peak hours. **Commercial:** Measured on a 12-month rolling basis over a 15-30-minute period calculated monthly.
South Australia	SA Power Networks	Measured over a 30-minute period during peak hours.

Source: ENA

United States network demand prices are offered to residential consumers in 15 states. The Rocky Mountain Institute survey of network demand charging is a good source of demand pricing initiatives in the US.[47]

Figure 34: Advantages and disadvantages of network peak demand pricing

Advantages	Disadvantages
Investment costs at times of peak demand are more visible.	Peak pricing can initially be hard for consumers to understand, resulting in a poor response if introduced as a standalone charge. Best applied as multi part pricing
Allows the distributor to target charges into both the peak demand window (time of day and duration), as well as at the nature of the peak	Risk of material rate shocks to some consumers. Some consumers will not able to avoid consumption at peak periods and may not be able to afford to pay
Allows the distributor to manage the impact of the peak on the consumer bill (eg. by averaging several peaks)	Retailers may not pass a demand charge through in their prices if they bundle network demand charges
Better matches network cost drivers than other types of pricing	Large reputational impact for distributors if this is not implemented correctly and resulting complaints and/or adverse media will likely result in increased administrative costs.
Provides an effective long-term transition path to increase the granularity and scope of the peak demand charge for the benefit of both consumers and distributors	Metering – network demand pricing will be difficult to implement with some meter configurations. If consumers do not have smart meters, a distributor will need to use profiling to estimate consumption during the periods of fixed demand. This will incur costs.
More choice for consumers on when to use energy	Consideration will need to be given to both retailer's and the distributor's ability to alter their billing systems to accommodate the new structures, assuming the retailer will pass through the distributor's demand charge.
Leads to lower prices over the long-term due to strong peak pricing signals decreasing the need for future network augmentation in response to system growth.	

[47] James Sherwood et al. *A review of alternative rate designs Industry experience with time based and demand charge rates for mass market customers* (Rocky Mountain Institute May 2016).

Source: ENA

Options for alignment

The examples of TLC and Orion (along with the outlined suggestions for enhancement) provide a basis for distributor alignment when looking to implement dynamic peak network demand pricing.

For fixed period network demand pricing, the following pricing template is proposed as an option for alignment.

Figure 35: Network peak demand template option

PRICE OPTION **Simple definition**	**NETWORK PEAK DEMAND** **(Coincident Maximum Demand)** ***$/kW/day price based on actual max. demand***
Detailed definition	Pricing based on actual maximum demand (kW) within a pre-defined peak period by month. Charge will vary from month-to-month with reset of maximum demand value. Consumer is rewarded by minimizing 'needle peak'
Peak definition	• Weekday-only peak • Morning 7-11am, evening 5-9pm
Unit of measure	kW
Time interval	Half hourly
Period of measure	Monthly measurement of one half hour period
Example	Summer = $0.07/kW/day Winter = $0.14/kW/day
Default	Profile
Alternative price structure	• Annual demand charge with a greater period of measurement. For example, Orion uses 200-300 half hour periods to determine its annual peak. • Peak definition based on fixed period network peak (rather than during pre-defined peak periods)

8 Capacity Pricing

Capacity pricing is like demand-based pricing. Charges are based on an agreed maximum demand (kW). By comparison, customer demand pricing is based on a consumer's actual maximum demand. Capacity pricing reflects the capacity service provided and signals the cost of reserving capacity to be available for the consumer to use regardless of whether they use that amount of capacity. According to the CEER Guidelines of Good Practice for Distribution Network Tariffs both European literature reviews and EC public consultation "indicate a general support for a move towards capacity based charging with the option of a hybrid of capacity and consumption based charging to incentivise a change in consumer behaviour."[48]

Two alternate formats of capacity have been considered in this report, installed capacity, which is limited by the fuse size installed on the line that serves a consumer or by a limiter installed on the meter board on the house; or booked capacity, which is the capacity or maximum energy deliverable during a period that has been agreed between the distributor and the consumer.

Feedback received from submissions show a stronger preference for other forms of pricing rather than capacity pricing.

8.1 Installed Capacity

How a network is designed and built drives the greatest share of distribution system costs which, in turn, is driven by consumer requirements for energy at its peak demand. Therefore, it is the assets required to be installed throughout the network to enable the delivery of energy during peak demand that drives investment. This implies a causal link between capacity available to the consumer and the charges to the consumer.

Some distributors may consider a single capacity charge would be the most appropriate. However, a single capacity charge does not capture all investment decisions, particularly around service quality and management of line losses. Therefore, other types of pricing may also need to be used in conjunction with installed capacity to be truly cost-reflective.

Installed capacity pricing is relatively simple, stable, and predictable. This can be advantageous for customers who dislike fluctuating energy bills and for retailers who offer these types of tariffs as it reduces their risk of variable distribution charges. Installed capacity is also seen as a low cost for distributors as meter readings are not required. However, there is the potential for higher charges for low energy users, and installed capacity does not encourage energy efficiency, as the capacity available is constant over time and does not necessarily reflect costs of network congestion at peak demand periods.

[48] James Sherwood et al. A review of alternative rate designs Industry experience with time based and demand charge rates for mass market customers (Rocky Mountain Institute May 2016).
EER_PUBLICATIONS/CEER_PAPERS/Electricity/2017/CEER%20DS%20WG%20Best%20Practice%20Tariffs%20GGP%20-%20%20external%20publication_final.pdf

Definition

Installed capacity pricing is a charge for having a certain capacity installed and available at a connection point. Capacity can generally be limited by fuse size or a limiter placed on the meter board for smaller connections. Capacity could also be limited by a dedicated transformer.

Design factor - capacity bands

As pole fuses are available in standard sizes, it is an obvious choice to provide capacity bands according to fuse sizes. Standard fuse sizes are provided in figure 36, which includes the fusing configuration and kVA rating as published in the ENA Pricing Guidelines.[49]

Figure 36: Standard fuse sizing

Fusing	Description	Phases	Amps	Volts	Calculated kVA	Rounded kVA
1Ph 30A	Single Phase 30 Amps	1	30	230	6.9	7
1Ph 60A	Single Phase 60 Amps	1	60	230	13.8	14
2Ph 30A	Two Phase 30 Amps	2	30	330	14.0	14
2Ph 60A	Two Phase 60 Amps	2	60	330	28.0	28
3Ph 20A	Three Phase 20 Amps	3	20	400	13.9	
3Ph 30A	Three Phase 30 Amps	3	30	400	20.8	21
3Ph 60A	Three Phase 60 Amps	3	60	400	41.6	41
3Ph 100A	Three Phase 100 Amps	3	100	400	69.3	69
3Ph 150A	Three Phase 150 Amps	3	150	400	103.9	104
3Ph 200A	Three Phase 200 Amps	3	200	400	138.6	138
3Ph 300A	Three Phase 300 Amps	3	300	400	207.8	207
3Ph 500A	Three Phase 500 Amps	3	500	400	346.4	345
3Ph 1000A	3 phase 1000 amps	3	1000	400	692.8	
3Ph 1250A	3 phase 1250 amps	3	1250	400	866.0	

[49] ENA (September 2016) *Pricing guidelines for electricity distributors - A handbook for pricing practitioners, Consultation Draft.* Available at: http://ena.org.nz/wp-content/uploads/2016/09/ENA-Price-Guidelines-web.pdf

8.2 Current experience

New Zealand

Installed capacity tariffs are not used in New Zealand for residential consumers on a widespread basis. They are more commonly used for larger customers by some distributors. For example, Vector has a capacity charge for commercial customers.

International - Netherlands capacity based charges

Since 2009, small consumers in the Netherlands have paid a flat capacity charge for electricity distribution. Most small consumers have a limited connection. However, for households with heat pumps or higher capacity requirements, higher capacity connections may apply. During the first two years of the capacity charges, consumers requiring greater capacity but with lower than average consumption were incentivised to reduce their capacity connection either by reduced tariffs or by receiving a lump sum to assist with the transition to lower capacity. Energy tax rebates on the total energy bill were also available to consumers with low consumption.

According to a CIRED workshop paper, the introduction of capacity pricing reduced administration costs for the distributor and reduced data errors, which assisted retailers with their billing accuracy and timeliness as less data was exchanged. [50]

The key drawback was that the charges did not always provide sufficient incentives for investment in energy efficiency and renewable generation. As such the energy tax was increased to provide greater incentives. This was designed to minimise any effect on small consumers.

Norway - installed capacity charges

In Norway electricity distribution charges currently consist of a fixed charge per annum plus an energy charge. Customers with installed capacity over a certain level are charged an additional amount based on used capacity as well as the fixed and variable energy charge. For future tariff design, the view of the Norwegian Water Resources and Energy Directorate (NVE) is that capacity drives network costs, therefore capacity is an appropriate method of charging for distribution services. NVE are considering three types of charges, including installed capacity, subscribed (booked) capacity and measured capacity (demand). In their assessment, they state that “Tariffs based on the customers’ physical installation are not very dynamic. However, it provides predictability in cost and revenue for both the customer and DSOs.”[51]

[50] Mandatova, P., Massimiano, M., Verreth, D., Gonzalez, C., (June 2014) Network Tariff Structure for a Smart Energy System. CIRED Workshop – Rome, Paper 0485.

[51] NVE, (2016) Status of NVE’s work on network tariffs in the electricity distribution system English summary 62:2016

The NVE consumer survey[52] of capacity tariffs found that installed capacity was "perceived as inflexible" and that consumers were uncomfortable with the potential for inconvenient power cuts should they exceed their current installed capacity. This view was tempered somewhat when the potential for agreed (booked) capacity was introduced as an option.

Advantages and disadvantages of installed capacity charges

Figure 37: Advantages and disadvantages

Advantages	Disadvantages
Capacity pricing is easy to explain and to understand, which should make it easier to implement.	Installed capacity pricing is not fully cost-reflective as there are other network costs such as line losses and quality. Other types of pricing will be needed in conjunction with installed capacity pricing to be fully cost-reflective.
Prices should be stable for consumers and retailers as changes will only occur where consumers request a change in capacity. This change could be signalled in advance to retailers.	Installed capacity pricing is not fully cost-reflective as there are other network costs such as line losses and quality. Other types of pricing will be needed in conjunction with installed capacity pricing to be fully cost-reflective.
To reduce fuse size and therefore costs, consumers should be incentivised to spread their load outside of peaks to prevent excess charges.	Installed capacity is based on a household maximum demand which may not coincide with network peak demand.
Prices are reflective of network investment costs. The more capacity required, the greater the network charges.	Consumers will have no incentive to respond to peaks if required by the grid.
Consumers who have invested in generation but still require capacity will be charged the same capacity charge as every other household without generation. However, someone who invests in gas appliances will be able to reduce their capacity charges.	There are additional costs associated with replacing fuses when required.
There is no requirement for smart meters to enable the use of installed capacity pricing therefore costs should be lower for distributors	Pricing by connection point fuse size is reliant on data which may not be accurate.
	Pole fuses are a somewhat "coarse" form of limitation on capacity as they are built to allow excess capacity of at least twice their rating for up to 3 hours.
	Some low user consumers may experience higher bills.

Source: ENA

[52] Trondelag R & D Institute, (2016) Consumer Survey regarding capacity Tariffs English Summary NVE Report 86:2016

8.3 Other considerations

To be compliant with the LFC regulation, a consumer needs to be able to change their capacity at a reasonable cost and within a reasonable period if the installed capacity charge is to be considered variable. Distributors will therefore need to have a process in place to enable this to be undertaken without undue delays and expense.

8.4 Booked (or "Nominated") Capacity

The key difference between the demand and capacity pricing is that demand pricing is predicated on *actual* demand whereas booked (also referred to as "nominated") capacity pricing is predicated on *agreed* demand.

The agreed demand will change from period to period reflecting a consumer's actual maximum demand during that period. The chargeable quantity of the latter will generally be consistent from period to period as a consumer's demand requirements are pre-determined and the frequency of plan changes is limited. Changes will only occur with a change in plan (upgrade / downgrade) or a breach of booked capacity.[53]

Definition of booked capacity

Booked capacity pricing is based on an agreed maximum demand level at a consumer's premise. The agreed maximum demand level would be set on a standing charge basis which sets out the increment (or "step up") in demand level available.

In many respects, it is like the 'plans' available in the telecommunications industry, where consumers can, for instance, choose between various levels of bandwidth and usage (eg, ADSL, VDSL, or fibre at different levels of capacity such as 100 Mbps, 200 Mbps, or 1Gbps). A key feature of these pricing arrangements is that:

- the consumer has choice
- the consumer pays more for a superior service
- access is not lost to the service if a breach of plan occurs.

A key design feature of capacity pricing is the continued delivery of an essential service in the presence of a breach of the chosen plan. An excess charge could be applied if the booked capacity is exceeded, rather than a cut in power, to encourage the choice of the best fit for their needs. Alternatively, the consumer may automatically be upgraded to the more appropriate plan in response to the breach with a requirement to stay on this plan for a given period before the consumer can request to be downgraded again. Or a rebate incentive could be offered if the booked capacity is not exceeded.

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[53] Depending on the design of the pricing structure. A breach resulting in a power may, for instance, may not affect the chargeable quantity.

Designing a booked capacity price

Capacity can be measured in kVA or kW. The preferred unit of measure is kW, as the advantages associated with greater understanding of a kW are considered to outweigh the disadvantages associated with less precision with the chargeable quantity to the network impact.

Design factor - time interval

As discussed in the section on customer demand pricing, the preferred time interval is half hourly, a common feature of advanced meters. This also corresponds to the resolution of the wholesale market where real-time retail types of pricing are available through retailers.

Design factor - period of measure

The same considerations apply for the period of measurement as were discussed in section 7.2 regarding customer demand.

Design factor - starting measure

Notwithstanding the intention to provide consumers with the choice of capacity level with this pricing structure, for the sake of convenience the starting capacity plan will be based on the consumer’s historical demand, rounded up to the nearest available capacity increment. It is recommended that the historical period is 12 months.

Design factor - plan changes

The number of plan changes permitted must balance the ability and desire for the consumer to ‘right plan’ for their energy requirements while limiting both the administrative burden and the opportunity to arbitrage a non-seasonal plan. It is proposed that one plan change is permitted per year.

Design factor - How is a breach managed?

Breaches can be managed by:

- charging for the over-use at a higher price (called an excess charge)
- providing a rebate to all consumers who stay within plan but those who breach will forgo the rebate payment
- assigning the consumer to a higher capacity plan, which would require a minimum mandatory period on the new plan to ensure the flexibility to change plans is not abused.

It is proposed that a breach is managed by assigning a consumer to a higher capacity plan for a minimum of 12 months. Although the rebate mechanism and excess charge give consumers greater choice and responsibility for the way they manage their energy requirements, the excess charge may prove unpopular because it is considered punitive. The rebate mechanism is also impractical to implement as preliminiary analysis shows that most customers are better off choosing the lowest capacity plan and consistently breaching.

The excess charge may also not comply with the LFC regulations (10 (2) (a)) that prevent "variable charges for domestic consumers that are tiered or stepped according to the amount of electricity consumed".

The automatic upgrade to a higher plan on breach has a greater administrative burden than its alternatives, but while the LFC regulations are in place, in their current form, it represents the only tenable option for managing breaches.

Design factor – capacity increments

Increments will need to step up in a linear manner (2kW, 4kW, 6kW, etc) with the same price per kW to ensure consistency with the LFC Regulations which prohibit stepped pricing. A linear price may best be presented as "for every **X** kW demand".

The size of the increment steps should be wide enough to be meaningfully distinguishable from a variable demand charge but narrow enough to provide a reasonable array of consumer choice and control to enable reward through improved energy use.

It is proposed that increments of 2kW are used, which would result in three relevant plans (2kW, 4kW and >6kW).[54]

International experience

Residential capacity pricing is not common internationally, although it is used in France, Italy and Spain.

Spain

Residential electricity prices in Spain are determined by potentia or power rating. The power supply rating (set in increments of 1.1kW) is usually shown on the consumer's meter. The 'capacity' charge is a function of the chosen power supply rating multiplied by a factor of 2 (if below 15kW) or 3 (if above 15kW) multiplied by the standing tariff. Importantly, the standing charge is payable irrespective of whether electricity is consumed, rendering it a genuine capacity price. Consumer supply will trip if demand exceeds the agreed power rating at the premises. The consumer can request the utility to upgrade (or downgrade) their power supply rating.

France

Residential electricity prices in France are also a function of *puissance* or power rating. Under the so called 'Blue' tariff, the power supply ratings are available in increments of 3kW. The rating is usually shown on the consumer's meter. The standing or 'capacity' charge is a function of the chosen power rating of supply. Like arrangements in Spain, the French standing charge is payable irrespective of whether electricity is consumed, rendering it a genuine capacity price. A consumer's supply will trip if their demand exceeds the agreed power rating at their premise.

In the presence of this pricing design, consumers have responded by adopting technology such as the *délesteur*. This device enables on-site load control by switching off appliances it is wired to (such as electric hot water cylinders and space heating) during high electricity demand.

[54] Preliminary research by Vector suggests this would cover 98% of the residential population in its distribution network.

Other considerations

Price levels

The booked capacity price component should be structured as a linear price to comply with the LFC Regulations. The LFC guidelines published by the EA provide clarification on the rule prohibiting tiered or stepped variable charges for many residential consumers.

Linear capacity price

Where a rebate mechanism was in place, the level of the linear capacity price would be similar, but generally lower, to a demand pricing structure. This reflects the expectation that a consumer's actual demand is usually less than their agreed demand. The extent to which the agreed capacity price is less than the demand price a function of the size of the rebate. In other words, the higher the rebate, the higher the linear capacity price.

Rebate (if applicable)

The rebate should be large enough to incentivise consumers to select, and stay within, the right capacity for their needs, but not so high as to be unduly punitive if missed. This will, in turn, be sensitive to the proportion of the network bill that is recovered from a capacity charge (keeping in mind that the capacity charge may be one of several price components that make up a residential price). The decision should also reflect a distributor's view of a consumer's responsiveness and understanding of a rebate. It may be preferable that a rebate is introduced at a relatively low level but increased over time in response to the frequency of breaches and the consumer's improving understanding of the new pricing.

Excess charge (if applicable)

The level of the excess charge should be high enough to incentivise consumers to select the right capacity for their needs but not so high as to be unduly punitive. This will, in turn, be sensitive to the proportion of the network bill that is recovered from a capacity charge. The decision should also reflect a distributor's view of a consumer's responsiveness and understanding of an excess charge. It may be preferable that an excess charge is introduced at a relatively low multiple of the linear capacity charge. It may be increased over time in response to the frequency of breaches and the consumer's improving understanding of the new pricing.

Figure 38: Advantages and disadvantages of Booked Capacity

Advantages	Disadvantages
Capacity pricing is highly cost-reflective as it aligns with the capacity service provided by the distribution network.	Major billing system changes required
LFC Regulations' issues (regarding stepped pricing) likely avoided by setting linear charging framework	Need to manage consumer change requests for capacity plans
Consistency in month-to-month charges (if usage within capacity)	Consumer uncertainty of capacity needs
Familiarity with 'all-you-can-use' telco plans	Capacity breaches perceived as punitive

Source: ENA

Enablers and constraints

Metering

The capability of metering infrastructure at the consumer's premises will dictate the nature of capacity pricing design. In the absence of advanced metering, capacity pricing may be based on a consumer's fuse size, representing the maximum amount of demand that can be drawn at a premise. Consumers can respond to the price signal by downgrading the capacity at their premises, recognising that a breach of capacity will result in a blackout (as the fuse "blows").

The presence of advanced metering enables a more sophisticated pricing design that can incorporate consumer choice in the level of capacity desired. This is because advanced metering captures maximum demand at a short time interval – of say, half an hour.

Billing systems and information exchange

Booked capacity pricing introduces added complexity to current billing arrangements. No longer is a network bill simply the function of metered quantities and days connected to the distribution network. Under a capacity arrangement, an additional, non-metered chargeable quantity is required: a consumer's desired capacity.

This introduces complexity through additional processes between the consumer and retailer, and retailer and distributor, in conveying, recording, and changing the capacity plan. The extent of that complexity will vary depending on the number, frequency, and timing of the plan change. For example, allowing a consumer to change plans mid-way through a billing period may bring added complexity to the design of both network and retail billing systems, compared with requiring plan changes to occur at the start of a new billing period.

Consumer impacts

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. This is primarily due to the change in unit of measure for the chargeable quantity (from kWh to kW).

Electricity Authority (September 2015) - Implications of Evolving Technologies for Distribution Pricing (page F)

There is no single 'right' pricing structure for all distributors because each distributor faces different circumstances. The appropriate pricing structure for the individual distributor in each location depends on a range of factors including:

- *Whether the network has enough capacity to cope with consumer demand (when it is at its peak) or has substantial spare capacity*
- *Whether consumer demand on any given network is growing or shrinking*
- *Variability and predictability of demand, which may differ between distributors*

Options for alignment

Figure 39: Booked capacity template option

PRICE OPTION ***Simple definition***	**BOOKED CAPACITY** **(all-you-can-use)** ***$/kW/day charge based on agreed max. demand***
Detailed definition	Pricing based on agreed maximum demand (kW) band. Charges will be consistent from month-to-month if demand stays within band. Automatic upgrade to a higher plan on breach, for a minimium period of 12 months
Peak definition	N/A
Unit of measure	kW
Time interval	Half hourly
Period of measure	Monthly

9 Pricing design

9.1 Pricing template menu

The implementation of new, more cost-reflective types of pricing provides an opportune time for distributors to increase alignment of their pricing. The following table collates the pricing templates developed in previous sections. This provides a menu of standardised types of pricing that distributors could choose to align to.

The pricing guidelines first published by the ENA in 2015 and revised in 2016, highlighted a need to standardise terminology so that agreed terms are defined in the same way across all networks. Identifying a menu of types of pricing is consistent with this.

This does not imply that pricing structures need to be the same across distributors. As pointed out earlier, each distribution network is likely to have characteristics that are shared with other networks, but also may have factors that make it unique.

The types of pricing in the pricing menu set out below are not necessarily stand-alone. That is, they could be used in combination with each other. For example, a capacity charge may be used in combination with a charge that signals congestion (e.g. ToU or network demand)

PRICE OPTION Simple definition	TIME OF USE $/kWh price varies with time of day	BOOKED CAPACITY (all-you-can-use) $/kW/day price based on agreed max. demand	CUSTOMER PEAK DEMAND (Anytime Max Demand) $/kW/day price based on actual max. demand over 12 months	NETWORK PEAK DEMAND (Coincident Maximum Demand) $/kW/day price based on actual max. demand
Detailed definition	Pricing based on consumption (kWh) which varies with the time of day and day of year, with 'peak' charge periods set higher than 'off peak' periods. Peak periods are pre-defined and set regarding when load on the network is highest. Consumer is rewarded by lowering or shifting usage outside of peak times.	Pricing based on agreed maximum demand (kW) band. Charge will be consistent from month-to-month if demand stays within band. Rebate provided for consumers that stay within agreed band. Breach of band will result in forgoing rebate	Pricing based on measured maximum demand. Charge reset annually. Consumer is rewarded by managing their load.	Pricing based on actual maximum demand (kW) within a pre-defined peak period by month. Charge will vary from month-to-month with reset of maximum demand value. Consumer is rewarded by minimising 'needle peak'
Peak definition	• Weekday peak: Morning 7-11am, evening 5-9pm • No shoulder period	N/A	N/A	• Weekday-only peak • Morning 7-11am, evening 5-9pm
Unit of measure	kWh	kW	kW	kW
Time interval	N/A	Half hourly	Half hourly	Half hourly
Period of measure	N/A	Monthly	Annual measurement. Number of half hours to be determined by distributor.	Monthly measurement of 1 half hour
Example	Fixed $0.15/day Peak $0.15/kWh Off peak $0.05/kWh	Fixed $0.15/day Plan For every 2kW $0.40/kW/day Rebate $5/month	$0.20/kVA/day	Summer $0.07/kW/day Winter $0.14/kW/day
Default	N/A	Historical kW demand	Profile	N/A
Excess charge	N/A	Yes	N/A	N/A
Alternative price structure	• Peak: 7am-9:30am, 5:30pm-8pm, Shoulder: 9:30am-5:30pm, 8pm-10pm Workday peak	• Replace excess charge for breach with automatic upgrade into higher, more expensive plan Deem plan based on actual fuse size	• Monthly rolling 12 months	• Annual demand charge with a greater period of measurement. By way of example Orion uses 200-250 half hour periods to determine its annual peak. • Peak definition based on ex-post network peak (rather than during pre-defined peak periods)

Source: ENA

9.2 Assessment of types of pricing

The ENA has developed a set of criteria for assessing the five cost-reflective types of pricing. The criteria cover efficiency, consumer, retailer, and implementation issues. These have been developed regarding:

- guidance provided in the EA's pricing principles, economic and decision-making framework, and distribution pricing consultation paper
- an international review of research into cost-reflective network pricing.[55]

The ENA's assessment of the five proposed types of pricing against the criteria is summarised in the table below.

Some broad observations are:

- Economic efficiency: The five types of pricing are more cost-reflective than the predominant legacy distribution pricing structures used today (eg, anytime or all-inclusive prices). Capacity pricing best recovers fixed costs in a non-distortionary manner, while network demand best signals network constraints and signals efficient investment in new technologies
- Consumers: Network peak demand pricing has the potential to result in an effective consumer response in load shifting (or shedding). However, ToU and capacity pricing may be more understandable for consumers.
- Retailers: Significant billing system changes are required for many retailers, particularly for demand types of pricing. ToU and capacity prices appear to be the types of pricing that retailers are most likely to pass through to consumers.
- Distributors: Network demand is the most durable option, however it presents numerous implementation challenges, as compared with ToU.

We have not come to a conclusion on the preferred option. We note there are significant trade-offs across the types of pricing, including in relation to economic efficiency versus consumer, retailer and implementation consideration. We make the following general observations:

- The types of pricing will be more cost-reflective and durable than current pricing. They will signal the cost of providing network capacity relative to the costs of consumer investments in other alternative energy types of pricing.
- A combination of a capacity/customer-demand and demand/ToU charges may be appropriate to reflect efficient recovery of existing capacity while signalling future upgrade costs:

[55] The criteria chosen follow internationally accepted criteria used in past rate design studies especially those of Professor Bonbright, whose choice of criteria become a standard for the industry. Professor's Bonbright's criteria please are discussed in The Regulatory Assistance Project (RAP) http://www.raponline.org/document/download/id/ and KPMG Australia's paper on tariff reform http://www.ena.asn.au/sites/default/files/electricity_network_tariff_reform_handbook_may_2016.pdf. Professor Bonbright's paper can also be viewed at: http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

- a stronger weighting towards capacity/customer-demand charges may be more appropriate where the distribution network is unconstrained. This also provides for a broad-based charge across all consumers, which is useful for recovery of fixed and sunk costs.
- a stronger weighting towards ToU/network-demand charges may be more appropriate where the network is approaching capacity constraints and the distributor needs to incentivise shifting of load away from congestion periods.

- Consumer acceptance of future types of pricing is dependent on how simple, fair, predictable, and stable each pricing option is. The most efficient and cost-reflective pricing approaches may not be the most readily accepted and require significant resource for consumer education and engagement to be successful.
- The cost and effort required to implement and manage the half hour (HH) based types of pricing will be higher than for other types of pricing. The industry's billing and data management systems are generally not ready to accept HH mass market billing. Significant investment by distributors, retailers, and meter service providers is required. The industry will also need to co-ordinate to confirm billing protocols and to develop half hour billing estimate and profile methodologies.
- Fixed pricing can be used in conjunction with other pricing components discussed in these guidelines.

The five types of pricing are compared against each other and are assessed using the following rankings:

	Significant benefit from adoption of proposed option
	Positive benefit from adoption of proposed option
	Costs and/or issues arise from adoption of proposed option
	Significant costs or issues arise from adoption of proposed option

Our assessment of considerations is informed by our survey of retailers as well as feedback received on the consultation. The survey was sent to all retailers. We received feedback from 15 retailers, including all the large retailers and many of the mid-tier (1%-10% market share each) and smaller retailers (<1% market share).

The feedback received provided a wide range of views on stakeholder's preferences for pricing reform, in response to the questions that the draft report asked. There is a summary of stakeholder views on the ENA website at: http://ena.org.nz/lines-pricing-options-submissions/

PRICE OPTION *Simple definition*	**TIME OF USE** *$/kWh charge varies with time of day*	**CUSTOMER PEAK DEMAND** *$/kW charge based on actual anytime max. demand*	**INSTALLED CAPACITY** *$/kW charge based on installed fuse capacity size*	**BOOKED CAPACITY** *$/kW charge based on agreed max. demand within bands*	**NETWORK PEAK DEMAND** *$/kW charge based on consumer demand during times of network peak demand*
1. Economic Efficiency					
1a. Signals future network costs **- Prices efficiently signal future investment costs in network capacity**	+ Higher peak prices signal typical network constraint periods, incentivising avoidance of future capacity upgrades or requiring consumers to otherwise pay for these. Signal more diluted than Network Peak Demand charge due to use of kWh and longer peak measurement period	− Signals future capacity costs better than traditional prices, but only where a consumer's anytime demand reflects use of network capacity during congestion periods	− Signals future capacity costs better than existing prices, but only where fuse size reflects consumer use of network capacity during congestion periods	− Signals future capacity costs better than existing prices, but only where booked capacity reflects use of network capacity during congestion periods	++ Peak demand prices strongly signal network constraint periods, incentivising avoidance of future capacity upgrades or requiring consumers to otherwise pay for these
1b. Efficient cost recovery **- Pricing enables efficient recovery of existing sunk costs from consumers using a cost-reflective and non-distortionary charge**	− Aligns recovery of existing investment in capacity with consumption at typical peak times, but may distort use by shifting consumption to non-peak periods or alternative energy sources	+ Aligns recovery of capacity costs with individual capacity requirements. AMD is less distortionary than CMD although it does incentivise consumers to reduce demand at all times	+ Broadly aligns recovery of capacity costs with individual capacity requirements, subject to accurate fuse sizing. Generally non-distortionary as fuse size is not changed often	+ Aligns recovery of capacity costs with individual capacity requirements, and is generally non-distortionary	− Aligns recovery of existing investment in network capacity with use of this capacity at typical peak times. Distorts use by shifting demand to non-peak periods or alternative energy sources
1c. Equitable (Causer/Beneficiary Pays) **- Prices fairly reflect the cost incurred resulting from individual consumer actions and/or enable cost recovery from consumers who benefit from service provided** **- Alternatively, consumers placing the same demands on the network pay similar charges**	+ Higher charges for connections that cause or benefit from network peak capacity investments, although cost reflectivity diluted compared to network peak charge	+ Generally higher charges for connections that cause or benefit from network capacity investment. However, peak usage may not always coincide with network congestion periods meaning charges may not always reflect the causer / beneficiary	+ Generally higher charges for connections that cause or benefit from network capacity investment. However, fuse size may not always coincide with peak usage during network congestion periods meaning charges may not reflect the causer / beneficiary	+ Generally higher charges for connections that cause or benefit from network capacity investment, subject to alignment with use of network capacity. Consumers have choice about the amount of capacity they want to sign up for. Excess charges may be viewed as unfair if punitive	++ Higher charges for connections that cause or benefit from network capacity investment
1d. Signals efficient investments in emerging technologies **- Prices are service based, efficiently signalling the costs of providing network services relative to the cost of other energy technologies (eg PV, EVs, gas)**	+ More cost reflective than existing charges reducing inappropriate incentives to invest in higher cost energy technologies compared to existing charges. May be too diluted to reflect full service cost on its own	+ More cost-reflective than existing prices, reducing inappropriate incentives to invest in higher cost energy technologies. AMD may not align to investments in network capacity	+ More appropriate service based charge which aligns to network cost drivers, reducing inappropriate incentives to invest in higher cost energy technologies	+ More appropriate service based charge which aligns to network cost drivers, reducing inappropriate incentives to invest in higher cost energy technologies	++ Aligns charges closely to network cost drivers during peak period reducing inappropriate incentives to invest in higher cost energy technologies
2. Actionable and Simple					
2a. Consumer response **- Consumers can choose to respond to price signals to manage their electricity usage and bills**	+ Consumers can choose to reduce or shift consumption from defined peak periods to reduce their overall monthly bills	− Consumers incentivised to reduce anytime maximum demand at all times, even when it may not reflect underlying network costs	− Consumers can choose to match fuse size to their peak capacity requirement, but may be relatively costly and not always operationally efficient	+ Consumers incentivised to reduce booked capacity to their peak capacity requirement and to manage anytime demand to avoid excess charges	+ Consumers incentivised to reduce or shift load from defined peak periods to reduce monthly bills
2b. Simple to understand **- Pricing is transparent and easily understood by a range of consumers and other stakeholders**	+ More complex than traditional pricing, but kWh usage is readily understood. Education required about new concepts eg peak vs non-peak	− Education required about new concepts eg kW, consumer peak demand and how to manage bills through reducing anytime demand	− Education required about new concepts eg fuse sizes.	− Simple to understand as similar in concept to broadband pricing, but education required about new concepts eg kW, excess charges	− Education required about new concepts eg kW, network peaks and how to manage bills at certain times.

PRICE OPTION **Simple definition**	TIME OF USE *$/kWh charge varies with time of day*	CUSTOMER PEAK DEMAND *$/kW charge based on actual anytime max. demand*	INSTALLED CAPACITY *$/kW charge based on installed fuse capacity size*	BOOKED CAPACITY *$/kW charge based on agreed max. demand within bands*	NETWORK PEAK DEMAND *$/kW charge based on consumer demand during times of network peak demand*
2c. Adoption costs **- implementation and on-going costs and resource requirements are manageable**	**Billing Systems:** Some retailers indicated they had billing system capability to implement; Others expected moderate to major investment to upgrade over a 1 to 2+ year period **Meter data:** A limited number of retailers/distributors can currently access/process HH meter data **Other implementation costs:** Low, mainly communications, education, and system upgrades **Ongoing costs:** Potentially higher from managing HH data	**Billing Systems:** Little billing system capability to implement; Retailers expect moderate to major investment to upgrade over a 1 to 2+ year period **Meter data:** A limited number of retailers/distributors can currently access/process HH meter data **Other implementation costs:** high from moving to kW demand eg communication, education, and system upgrades **Ongoing costs:** Potentially higher from managing monthly HH data and calculating AMD	**Billing Systems:** Relatively straight forward to implement where fuse size can be indentified by ICP **Meter Data:** No meter data required NB: Option not surveyed **Other implementation costs:** High from moving to fuse size eg communication, education, and fuse data audits **Ongoing costs:** Relatively low admin costs over time	**Billing Systems:** Few retailers indicated they had billing system capability to implement; Others expected moderate to major investment to upgrade over a 1 to 2+ year period **Meter data:** A limited number of retailers/distributors can currently access/process HH meter data **Other implementation costs:** High from moving to kW demand eg communication, education, and billing systems upgrades **Ongoing costs:** Potentially higher from managing HH data although capacity bands less variable	**Billing Systems:** Little billing system capability to implement; Retailers expected moderate to major investment to upgrade over a 1 to 2+ year period **Meter data:** A limited number of retailers/distributors can currently access/process HH meter data **Implementation costs:** High from moving to kW eg; demand communications, education, and billing systems upgrades **Ongoing costs:** Potentially higher from managing monthly HH data and calculating CMD
2d. Retailer pass-through **- Retailers are likely to transparently pass-through pricing structures**	Retailer survey and consultation paper submissions indicates that this is the most preferred approach	Retailer survey and consultation paper submissions indicate little support for this approach because it is viewed as inefficient. May also be difficult to align distribution and retailer billing cycles	Retailer survey and consultation paper submissions indicates limited support for this option, but relatively easy to pass-through where distributor identifies fuse size	Retailer survey and consultation paper submissions indicates limited support for this option	While retailers recognise potential efficiency benefits, there was limited support for this approach. May also be difficult to align distribution and retailer bill cycles
2e. Transition **- Implementation can be efficiently managed, particularly with retailers and vulnerable consumers**	kWhs retained, with analysis suggesting limited adverse bill impacts Relatively simple for consumers to understand. kWh charge aligns with retailer billing	Phase out of kWh charge with adverse bill impacts likely Consumer education required on management of AMD	Phase out of kWh charge with bill impacts likely Resource and education required to identify required connection fuse size and in changing out inappropriate fuses	Phase out of kWh charge with adverse bill impacts likely Education and resource required to help consumers select suitable capacity and manage excess charges	Phase out of kWh charge with adverse bill impacts likely Education required to manage demand during the network peak
2f. Accuracy **- Information and systems are available to support accurate implementation and billing of the pricing structure, including for non-metered loads**	Estimates required to correct HH data errors, but can be adapted from existing kWh based methodology. Difficult to apply where AMI unavailable	Upgrade to existing estimation methodology required to correct HH data errors or where AMI unavailable. Revisions may be difficult to wash-up transparently. May take longer to accurately process kW data Difficult to apply where AMI unavailable	Installed fuse size may not reflect actual capacity requirements. Consumer fuse size records may be inaccurate Good option where AMI unavailable	Upgrade to existing estimation methodology required to correct HH data errors or where AMI unavailable. May take longer to accurately process monthly kW data Difficult to apply where AMI unavailable	Upgrade to existing estimation methodology required to correct HH data errors. Revisions may be difficult to wash-up transparently. May take longer to accurately process kW data Difficult to apply where AMI unavailable
2g. Compliance **- Pricing structure is compliant with applicable regulations**	Traditional LFC compliance approaches apply	Appears to be consistent with the authority's LFC guidance, but needs testing	Appears to be consistent with the authority's LFC guidance so long as customers can select from a range of fuse sizes at a reasonable cost and timeframe. Needs testing	Appears to be consistent with the authority's LFC guidance, but needs testing	Appears to be consistent with the Authority's LFC guidance, but needs testing

PRICE OPTION Simple definition	TIME OF USE *$/kWh charge varies with time of day*	CUSTOMER PEAK DEMAND *$/kW charge based on actual anytime max. demand*	INSTALLED CAPACITY *$/kW charge based on installed fuse capacity size*	BOOKED CAPACITY *$/kW charge based on agreed max. demand within bands*	NETWORK PEAK DEMAND *$/kW charge based on consumer demand during times of network peak demand*
3. Supports retail competition					
3a. Supports retail competition **- Price structure can be applied across different distributors consistently with limited distortion to retail competition**	(+) Likely that pricing structures could be standardised Legitimate variation across distributors may arise to reflect network conditions eg different peak/ off-peak periods	(+) Likely that AMD pricing structures could be standardised	(+) Likely that fuse size bands could be standardised	(+) Likely that capacity bands and excess charge/discount structures could be standardised	(+) Likely that pricing structures could be standardised (−) Legitimate variation may arise to reflect network conditions eg from adoption of different peak/ off-peak periods
4. Durability and flexibility					
4a. Durability and flexibility **- Pricing structure has flexibility to respond to changing external circumstances (eg technology, consumer profiles)**	(+) More durable as technology neutral and more cost-reflective. More flexibility to respond to changing behaviours	(−) Less cost-reflective than other future pricing options given focus on AMD. Less durable over time as consumers adjust to ToU and demand concepts	(+) More durable as more cost-reflective and simple to maintain. Durable alternative option for consumers without AMI (−) Less flexible than Booked Capacity	(+) Technology neutral and more cost-reflective. Flexibility to respond to changing consumer behaviour	(+)(+) Technology neutral and the most cost-reflective
5. Stable / predictable					
5a. Stable **- Adverse bill changes are minimised for consumers, particularly for the most vulnerable consumers**	(−) Creates fluctuation in bills due to seasonality. Potential unexpected high bills if peak period consumption consistently higher, but impact of individual spikes in consumption is diluted	(− −) Creates fluctuation in bills due to seasonality. Potential unexpected high bills resulting from individual demand spikes. Impact diluted over rolling 12-month period, but individual demand spikes will apply for 12 months	(+)(+) Stable billing over time with no monthly volatility or annual seasonality	(+) More stable billing over time with no monthly volatility or annual seasonality in capacity band charge (unless requested) (−) Excess charges/discount may create unexpected bills for some months	(−) Creates fluctuation in bills due to seasonality. Potential unexpected high bills from individual demand spikes, but effect will only apply for 1 month.
5b. Predictable **- Price structure enables accurate financial planning for bills**	(−) More difficult for distributors and consumers to predict peak usage and bills	(−) More difficult for distributors and consumers to predict individual consumer peak demand and bills	(+)(+) Relatively predictable billing as fuse size does not change often	(+)(+) Relatively predictable billing from banded capacity charge (− −) Excess charge/discount less predictable	(−) More difficult for distributors and consumers to predict individual consumer demand at network peak demand and bills

9.3 Learnings from the literature

As part of the development and publication of these guidelines ENA utilised research from a variety of sources including peer reviewed literature, pilot study data and pricing currently implemented in network companies around the world.

From the literature, we drew the following conclusions:

- pricing based on LRMC enables efficient pricing
- sunk or residual costs should not be recovered through a distortionary pricing signal
- demand pricing best reflects an electricity network's cost structure where most costs are fixed in the short term
- for pricing reform to be successful, distributors must work closely with stakeholders and end users throughout the process
- there is no consensus as to whether efficiency considerations are more important than other considerations such as fairness or simplicity
- there is no consensus on whether consumers are willing or able to take up new forms of pricing, including but not limited to demand based pricing.
- implementation should consider such options as opt in, opt out, and shadow billing.

As part of our literature review we have also considered the EA's work to date on the Transmission Pricing Methodology, Distributed Generation Pricing Principles, and review of the distribution pricing principles. From these publications, we take the view that our approach is consistent with the approach the EA is taking to monopoly pricing reform. In particular, a focus on efficiency for the long-term benefits of consumers, the use or option to use LRIC to signal long run network costs, the use of fixed charges to recover residual (sunk) costs, as well as how new forms of pricing compare with the existing distribution pricing principles.

A list of the research we have consulted is provided in the bibliography section to these guidelines.

Part 4

Implementation and transition

10 Implementing new pricing

This section identifies technical issues that may act as barriers to distributors as they implement future pricing structures. Most of these issues have been confirmed by submitters in the recent Consultation Paper. We expect distributors and the industry will need to do further work to deal with these matters.

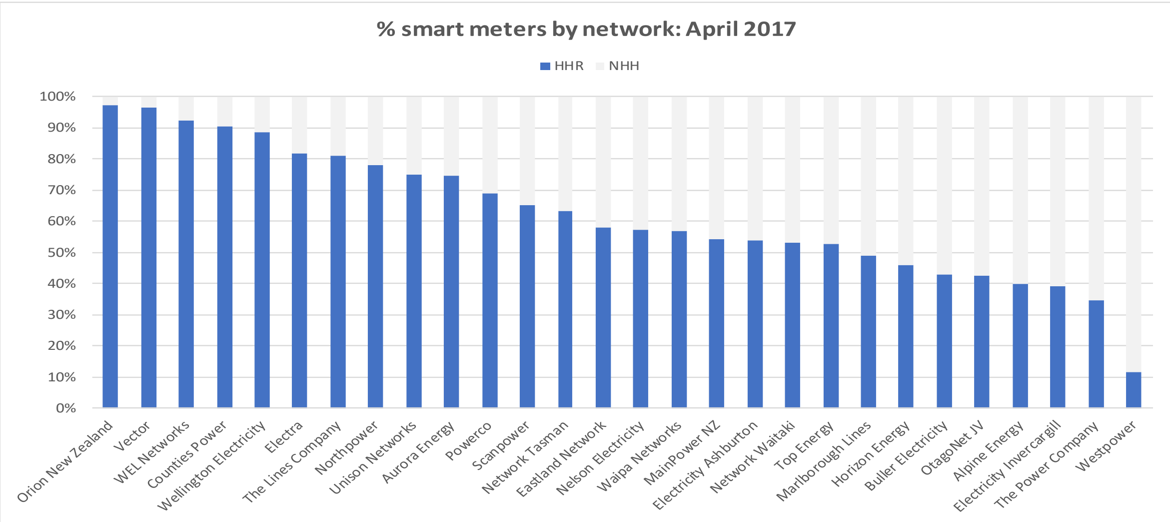
10.1 Getting access to data

Successful implementation of most of the pricing structures examined in these guidelines requires access to half hour (HH) metering data. The installed fuse capacity option requires access to fuse size data. Getting appropriate and timely access to this data is essential.

Availability of Advanced Metering Infrastructure (AMI) in supply areas

Mass market HH data is typically only provided by AMI (smart meters). A distributor must know how many smart meters are in their supply area to implement half Hour (HH) based pricing structures. As at July 2017, smart meters were still being installed throughout the country. A variety of electricity meters (both HH and Non-HH) are being provided by different meter providers (MEPs). This has led to different metering arrangements and deployment profiles across the country. While over 75 percent of connections have smart meters installed, Figure 40 below confirms that many distributors will not have complete smart meter coverage for some time. [56] And it is likely that some remote customers might never have smart meters.

Figure 40: Percentage of HH read meters by Network: February 2017



Source: EA EMI

[56] Link: Electricity Authority: www.emi.ea.govt.nz. Note – HHR excludes non-accredited HHR meters. For example, most of the HHR meters on Counties Power's network are HHR but are still to be accredited.

Distributors need to consider several key questions when preparing new pricing structures.

- What minimum penetration of smart meters is required before HH based pricing structures should be deployed?
- What pricing should be offered to consumers that do not currently have AMI?
- What pricing needs to be offered to consumers that may never have AMI (that is, remote connections)?

Each distributor will need to consider these questions based on its regional smart meter deployment timeframes and consumer profile. For instance, distributors in urban areas may expect to see close to 100 percent penetration of AMI relatively soon, so may be able to roll out new future pricing structures. Rural networks will have much slower and lower AMI penetration.

The risks of adopting HH based pricing structures too early, when AMI penetration is low, include:

- dilution of the effectiveness of communications and marketing campaigns
- consumer confusion as to their eligibility for new pricing structures
- longer transition periods
- greater reliance on meter estimates and work arounds
- added costs for retailers and distributors in managing two large pricing books, to cater for those consumers without smart meters.

Access to HH data

Many distributors do not own the smart meters required to extract HH data. These distributors rely on contractual arrangements, typically with the retailer under the terms of use of system agreements. Alternatively, distributors may seek access directly from meter service providers (MSPs) or deploy their own smart meters.

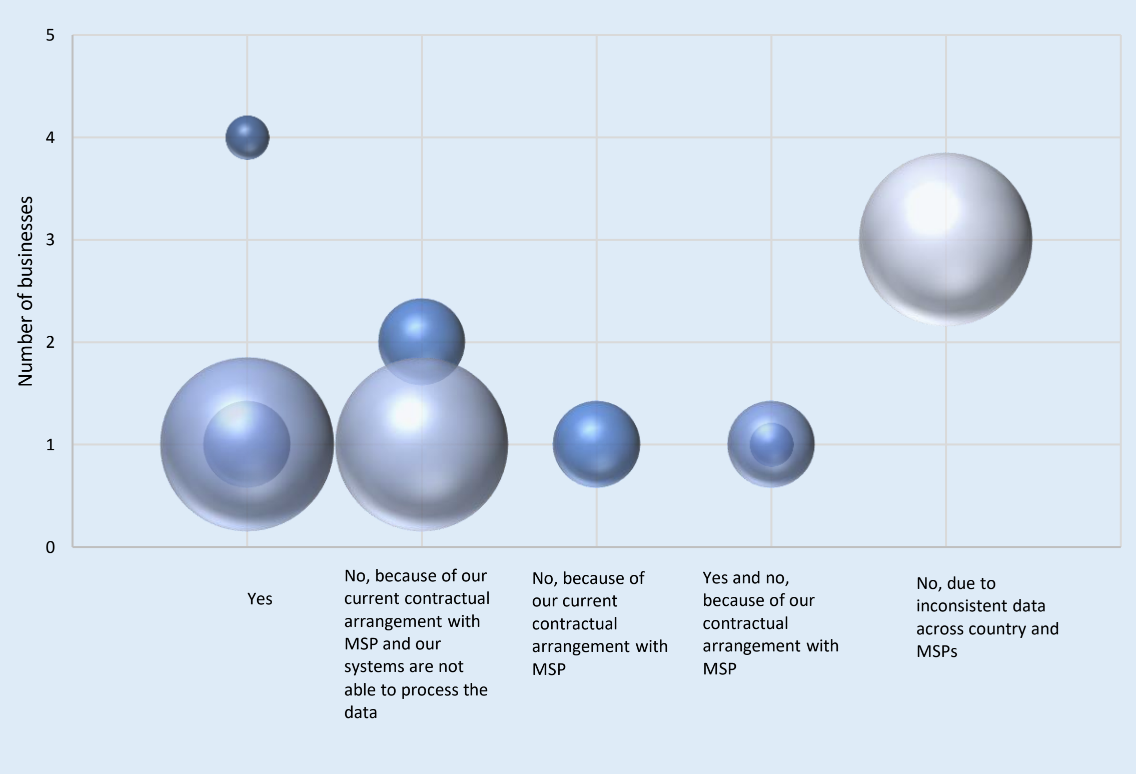
The ENA's retailer survey and the submissions on the discussion paper highlight several potential challenges with current arrangements for accessing data through the retailer. Responses suggest that many retailers cannot access HH data themselves through their own metering arrangements, so they will be cannot pass data to distributors. Common concerns expressed by retailers were:

- their systems could not process HH data (discussed below)
- their contractual arrangements with MSPs didn't provide appropriate access to HH data
- they could not access meter data consistently throughout the country given differences in AMI, different AMI deployment timeframes, and due to communications blackspots.

Figure 41 shows that only seven retailers (representing a range of different retailer types) from the survey indicated they had access to HH data (and one had some reservations). And, of those, only five currently have the system capability to aggregate the HH data into a format specified by the distributor.

It will take time, cost and effort for distributors and retailers to work together to resolve these data access issues.

Figure 41: Retailers with HH data



Legend

Source: ENA

Coordination and interoperability with meter data providers

Where a retailer or third party is the meter owner, it is important to establish a clear service level agreement (if it is not part of the use of system agreement). This should set out access criteria, including data formats, data aggregation, submissions, processing timeframes, and costs.

According to the guidelines on AMI, equal access should be provided and the meter owner should consider requests on interchange protocols. Clause 10.16 of the Electricity Industry Participation Code (the "Code") outlines obligations in terms of "metering data exchange timing and formats" which must be complied with.

Meter data providers or retailers may also be able to process billing data on a distributor's behalf. This could potentially save time and cost and may address the privacy concerns that have been raised (see below).

10.2 Data must be high quality

Meter data needs to be accurate and reliable to enable accurate billing under future pricing structures. Distributors will need to consider various levels of data quality that may affect the implementation of pricing structures.

Meter functionality

A distributor should consider whether smart meters in its supply area can provide minimum functionality for rolling out new pricing structures. A growing concern is the gap between what smart meters promised and what they can deliver. For instance, concerns exist over:

- whether all smart meters can provide reliable remote-read functionality (eg. some smart meters are in communications blackspots)
- the number of available meter registers
- errors and missing data throughout interval data.

Distributors must rely on a range of manual processes to resolve these issues, including manual reads and error correction using estimated profiles (discussed below). These manual processes will add cost and may create service delivery issues (for example, manual reads may delay monthly billing cycles; estimation techniques may result in billing anomalies).

Data estimates and profiles

In some cases, distributors need to apply estimated HH data based on profiling or assumptions to correct for errors and, potentially, to implement pricing for consumers without smart meters.

The retailer survey and submissions on the discussion paper generally accepted that HH estimation profiles will need to be adopted, but there were various concerns expressed about their use, including:

- *Accuracy:* Profiles do not accurately reflect actual consumption by consumers and are not necessarily consistent over all days of the week for residential consumers. However, some retailers noted that estimated profiles could be applied reliably in some situations (eg, annual and seasonal estimates).
- *Consumer response:* Only actual HH data will provide consumers with the information necessary for them to manage their load.
- *Variability:* HH profiles change continuously and profiles or assumptions can quickly become out of date if not regularly updated.
- *Consumer acceptance:* International studies, as well as the experience of those networks that have implemented HH-based pricing, have generally shown that consumers do not favour charges based on assumptions, estimations, or profiling.
- *Cost reflectivity:* profiles and assumptions should be cost-reflective, consistent with the pricing structure.

We generally agree with these views. We note the significant risks from adopting HH estimates and profiles for billing, particularly when applying HH-based pricing structures to connections without smart meters. However, estimation profiles need to be developed and regularly updated, even if only to provide for error correction.

We anticipate that distributors will need to work with industry towards developing sound, justifiable and transparent estimation, and profile methodologies if the preferred HH-based types of pricing are implemented. Distributors may also wish to consider working with data providers and retailers to apply HH estimation profiles and assumptions on their behalf, subject to pre-established criteria.

Over time we would expect use of estimation profiles to reduce as the deployment of smart meters progresses. However, profiles will continue to be relevant for error correction and a residual number of connections that are remote or in communications black-spots.

As an alternative, distributors could consider adopting a general non-HH based pricing approach for connections where robust HH data is not available.

Fuse size data

The accuracy and reliability of distributors' installed fuse data ranges from relatively poor to good, depending on how individual distributors have used and managed this data in the past.

Fuse data may not reflect what is installed on site. For example, contractors may replace fuses to resolve faults, but may not log changes appropriately in the network asset management systems.

In addition, current fuse sizes may not reflect the consumer's current capacity requirements, and charging on this basis may be inappropriate. A common example provided is where a consumer has previously requested 3-phase supply (for example, to run a welding machine). Through changes in circumstances (for example, if different owners move into the house) the fuse size may no longer be relevant to the consumer.

Distributors that choose to adopt the installed capacity pricing option may need to review their detailed fuse size data to ensure it accurately and appropriately reflects the consumer's current capacity requirements. This is likely to be a significant programme of work for some distributors in the early implementation phase. And there are likely to be ongoing costs in monitoring changes in consumer capacity requirements.

10.3 Data security and confidentiality issues

General confidentiality and security concerns arise in relation to the use of consumer HH data. Clause 10.15 of the Electricity Code outlines obligations regarding security of metering data. In line with the requirements of the Code, a secure and auditable process must be followed in moving/sending data for reconciliation or billing purposes.

Retailer submissions to the consultation paper were particularly concerned that distributors might use HH billing data to compete in non-network markets (eg retailing). Distributors must take care when dealing with consumer information, and keep to the confidentiality terms and conditions in its use of system agreements (UoSA) with retailers. Distributors must ensure that consumer data is not used for any purpose other than what the UoSA provides for. Alternatively, distributors will need to seek permission from consumers to use meter data for other purposes. This is consistent with the authority's view that the consumer owns the meter data.

10.4 Registry issues

The Electricity Authority's Registry allows the exchange of information between retailers, metering equipment providers and distributors to manage reconciliation, invoicing and switching processes. Part 11 of the Code details the management of information held by the Registry and outlines the process for switching ICPs between retailers, metering equipment providers and distributors.

Retailers' and distributors' views vary about whether changes to Registry profiles or the Codes are necessary. It is expected that new registry fields may need to be adopted (eg for booked capacity). This will require further consideration.

10.5 Electricity Information Exchange Protocols

Electricity information exchange protocols (EIEPs) provide a standard format for the exchange of information between industry participants. Opinions differ on whether changes to EIEPs are necessary. Several retailers noted in their consultation paper submissions that due to misalignment between the retailer and distributor billing cycles, the unbilled accrual adjustments for incremental normalised NHH EIEP1 will not work for monthly kW demand charges. Similar questions have also been raised over the 'as-billed' methodology. One retailer has suggested that the Replacement Normalised approach needs to be used for kW based charges. These issues will require further consideration by distributors and the industry.

10.6 Data Systems

Data management systems

Distributors will need to assess the resilience and capability of their current data management systems that collect, measure, process and examine large volumes of HH data (and potentially fuse sizes). This analysis is likely to reveal the potential need for upgrades of data management systems for some distributors. The costs and lead times involved may be significant and must be considered in planning.

Billing systems

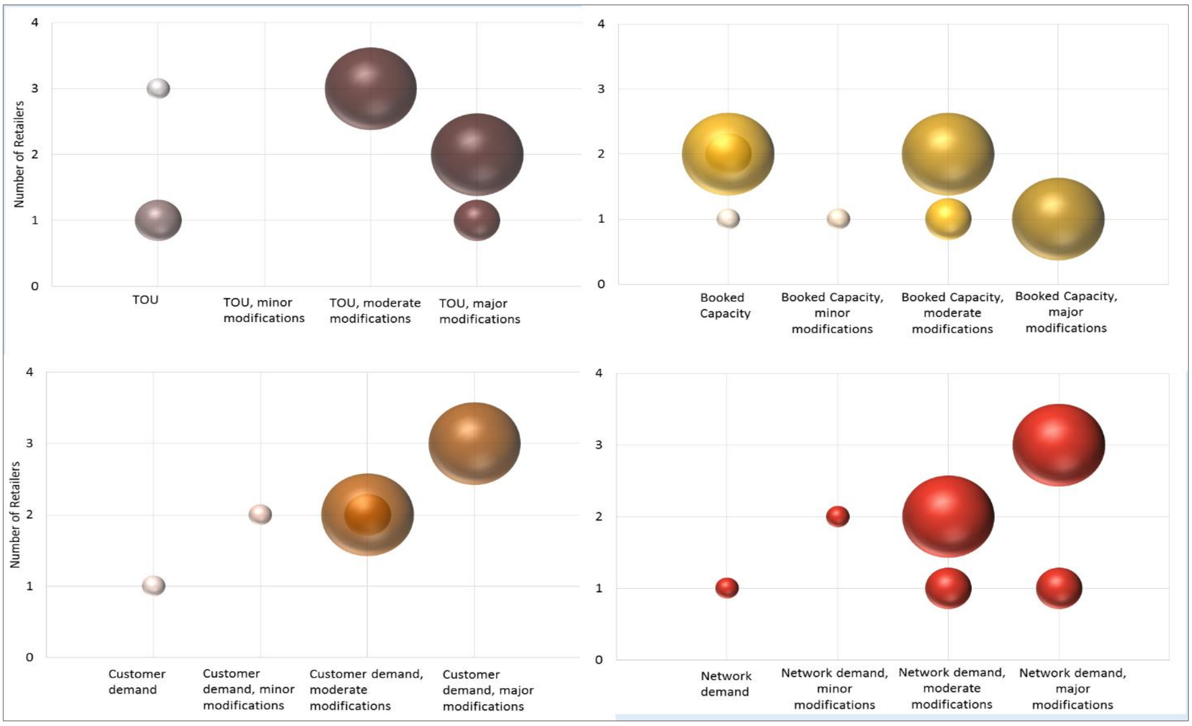
Distributors also need to consider their current billing system capability and whether it requires an upgrade to process bills for new HH-based pricing structures. Upgrades to retailer and data provider system interfaces may also need to be considered.

Again, sufficient lead times as well as consideration of the costs of adjusting billing systems (for both the distributor and retailer) need to be factored into planning. Retailer billing systems must also cater for future pricing structures to ensure they can pass through new distribution prices. Retailers gave the following feedback in the ENA's retailer survey and on the Discussion Paper:

- most retailers' billing systems will not have the capability to bill consumers under the preferred future price types
- the potential timeframes required to process and validate HH data may exceed the current billing cycle timeframes, particularly for billing of monthly HH data.
- most retailers estimate a timeframe of one to two years or more to upgrade their billing system capability, with upgrade cost estimates ranging from minor ($100,000 per retailer) to major (greater than $1 million per retailer).
- distributors should consider the merits of adopting consistent pricing structures to limit the number of billing system upgrades that retailers may need to make, and therefore the cost of these upgrades.

Figure 42 provides a breakdown of these views by retailer size (small, medium and large) by future pricing option.

Figure 42: Retailers with billing systems that can bill future pricing structures, and indication of potential magnitude of modifications required



Source: ENA

Ref legend to figure 41, page 94

11 Transition strategies

To succeed, any pricing initiative must involve plans and strategies for transitioning to structures that better reflect cost. The key objectives of transition should be to:

- encourage uptake of future pricing structures
- communicate the key features and benefits of any new types of pricing and build trust with consumers
- manage the effects on consumers during the transition
- engage with other stakeholders that will be affected by the change, or may support it.

11.1 Encouraging uptake

Successful pricing reform involves unlocking the value of new energy technology by providing incentives and choices for consumers. Developing plans and strategies that promote and encourage uptake is therefore very important to distributors.

Uptake of future pricing structures can generally be achieved through mandatory or voluntary adoption of future pricing structures, or through a combination of both. There are trade-offs between these approaches. Figure 43 gives some key features of mandatory and voluntary approaches.

Figure 43: Mandatory and voluntary approaches

Approach	Features	Considerations
Mandatory	• distributors or retailers assign connections to new prices • legacy pricing is closed to new consumers and discontinued once consumers are transitioned	• international examples suggest mandatory is more effective at driving uptake (about three to five times higher than opt-in approaches)[57] • clear course for closure of legacy pricing • more contentious; more likely to be challenged, increasing complaints, queries, and resourcing. • requires high uptake of AMI • likely to be greater consistency in pricing structures distributors may mandatorily apply pricing to retailer invoices, but this does not necessarily mean the retailer needs to pass this on to consumers on a mandatory basis.
Voluntary	• distributors encourage consumers to opt in to new pricing structures using a range of incentives	• international evidence suggests voluntary approaches result in lower levels of uptake • rewarding positive behaviour through incentives may be more acceptable then penalising negative behaviour • unclear when legacy pricing will end • promotes consumer choice, but needs to be supported by significant incentives • can lead to inefficient arbitrage between types of pricing • can provide shadow prices at the same time to highlight benefits of new pricing (shadow pricing shows what consumers would have paid under the new pricing structure so they can make decisions on clearly visible information)

Source: ENA

Submissions to the recent consultation paper express no clear preference for mandatory or voluntary approaches. However, several submitters suggested that adoption of pricing should be initially voluntary to allow retailers and consumers to adapt.

Combined approaches

A mix of voluntary and mandatory transition approaches can be more effective at driving uptake while providing the necessary consumer safeguards. Common approaches that have been considered elsewhere or suggested in submissions on the discussion paper are set out in Figure 44.

11.2 Communications about pricing changes

Future pricing structures give consumers new tools to manage their electricity usage. Consumers will need relevant information and support during the transition period so they can use these new tools effectively. Distributors need to communicate with consumers (directly or through a retailer) to:

[57] Rocky Mountain Institute, 2016, "A review of Alternative Rate Designs: Industry experience with time-based and demand charge rates for mass market customers" http://www.rmi.org/alternative_rate_designs

- tell consumers about the new prices and when they will apply
- explain how pricing structures work, including how usage will be measured
- explain the rationale and key benefits of cost-reflective pricing
- explain how consumers can manage their electricity use to lower their charges under the new pricing arrangements (for example, the focus is likely to be on managing energy use at peak times or use of alternative energy during the network peak)
- provide a forum to give feedback and ask questions, and give timely replies to common questions
- highlight that ToU/capacity/demand prices are not new and are used in New Zealand and overseas
- identify alternative types of pricing that may be better suited to individual consumers' circumstances (for example, for vulnerable consumers) and say where consumers can get further support or guidance.

International research suggests a long-term communication strategy is needed through the transition period and beyond to raise awareness and motivate consumers to change. Short-lived campaigns will often have a discouraging effect.[58]

Communications need to be easy to understand and targeted to a range of different types of consumers, including those with little understanding of how to manage their electricity.

As discussed in section 5.3, the ENA in conjunction with ERANZ have recently prepared consumer engagement guidelines that will recommend voluntary guiding principles for retailers and distributors undertaking consumer engagement activities relating to new options for distribution pricing.

[58] Groothius and Mohr (2014), "Do Consumers Want Smart Meters? Incentives or Inertia from North Carolina and Lessons in Policy", Economics of Energy and Environmental Policy, Volume 3, Number 1, Page 53-67

Figure 44: Common transition approaches

Approach	Description	Examples	Considerations
Mandatory with voluntary opt-out	A mandatory transition is complemented by an opt-out pricing option for those consumers that do not want to move to new pricing structures	This approach has been adopted by some Australian distributors (eg Jemena), who have provided a limited opportunity for consumers to opt out of demand-based pricing approaches	• Research suggests that this drives 3-5 times higher uptake than voluntary approaches, but results in lower levels of engagement • The opt-out pricing option: - will ordinarily be based on simple pricing structures (ie, kWh) - can be set to incentivise consumers to adopt the new pricing options - does not need to be a legacy price. Distributors may consolidate legacy pricing
Opt-in with shadow pricing	Legacy pricing supported by shadow bills of the alternative pricing structure that show consumers the savings under new pricing options	For example, opt-in demand price is adopted with an Anytime price shadow bill provided	• Some consumers will be worse off under new pricing options without behavioural changes • Making new pricing options attractive promotes greater uptake
Initial opt-in period, then mandatory	An initial opt-in period is provided to consumers. Mandatory adoption is applied once uptake has reached critical mass on the network	Suggested by ERANZ	• Making opt-in pricing attractive promotes greater uptake
Close legacy pricing to new connections	Legacy pricing is closed to new connections. Voluntary approaches and incentives to encourage existing consumers to switch	WEL Networks has adopted this approach for its new ToU Smart Pricing	• Avoids disruption of assigning existing consumers to new prices • Is effective at driving uptake where there is reasonable connections growth • Likely to align with AMI deployment in new areas • Discourages competition where some retailers have the capability to offer the new structures and others don't
Close legacy pricing when consumer switches retailer	Legacy pricing applies only up until the consumer switches retailer or price category, after which they will be assigned a new pricing option		• Requires significant coordination with retailers • May be difficult to apply in practice • May confuse consumers during switching process • Could be a barrier to switching
Mandatory approach applied to larger connections and voluntary approach for small connections	Mandatory approaches may be more effectively targeted to larger connections such as medium and large businesses. Voluntary opt-in approaches may be more appropriate for smaller connections	This approach has been adopted by CitiPower and Powercor in Australia, who apply mandatory approaches to large connections	• Larger consumers are likely to understand the new pricing better and have greater resources to manage electricity under future pricing structures • Inequitable treatment of consumers

Source: ENA

11.3 Managing adverse consumer impacts

Many consumers' bills will change when moving to cost-reflective pricing. Some consumers are likely to be worse off, and others better off during the initial transition. Understanding and managing significant adverse effects and reducing volatility, particularly for vulnerable consumers, will be a key priority during the shift to future pricing structures. In managing these impacts, distributors will need to consider:

- the impact of different pricing structures on different consumer groups, particularly vulnerable customers where electricity is a high proportion of their income
- the cost impact on the consumer's final retail bill, accounting for rebundling of distribution prices
- the transition approaches available to them (for example, mandatory versus voluntary approaches, as discussed above)
- acceptable maximum annual increases in charges
- the timeframe to transition consumers
- who will undertake the transition - the distributor or the retailer as part of their own retail packages
- clear communication and education of how pricing works and the potential impacts on individual consumers.

A key step in developing a transition plan is to analyse the potential impact of a new pricing structures on different consumers. This analysis should focus on the effect on individual consumers, rather than on consumer group averages which may hide significant price changes.

This analysis will help distributors to tailor a transition plan to a consumer population. Distributors can develop distinct transition approaches and implementation timeframes for different consumer groups.

Distributors will need to consider acceptable maximum annual increases, in consultation with other stakeholders. In turn, this will help determine a pace for transition, as a higher acceptable price increase will allow for a faster transition. The pace of transition will need to be weighted against other competing objectives. However, it may be possible to progress some consumer groups at a faster pace as they are less affected than others, or they may be more willing to adopt new price structures.

Several approaches can be applied to minimise the adverse effects of price changes. Some common approaches are summarised in Figure 45.

Figure 45: Approaches to minimise significant adverse prices changes

Approach	Description	Example	Considerations
Phased rebalance of prices	New prices are introduced in year 1 and increased annually over several years, while legacy prices are decreased annually until they are phased out	Jemena (an Australian distributor) plans to introduce a demand charge and gradually increase this over 7 years between 2018–2025. This will be offset by a corresponding reduction in and phase out of kWh charges over this period	• This approach introduces consumers early on to the concept of cost-reflective charges, with limited financial impact • Consumers have time to adjust their behaviour • Phasing results in yearly changes in pricing which prolong the effects of transition • Could be complemented with other transition approaches
Cap on price increases	A maximum annual price increase is applied over the transition period	Wellington Electricity recently applied a 6% price cap to minimise the effect of its 2016 price restructure	• A higher price cap will allow new prices to be introduced faster and vice versa • The actual impact on retail bills may be less, recognising that distribution charges are a small component of final bills
Cap on billed quantities	Peak demand/usage quantities are capped to minimise high bills over a transition period	Energex's Financial Risk Reduction Mechanism caps billable monthly demand at 5kW for an initial transition period	• The distributor must set the level of capped quantities • An annual rising cap could be applied to slowly increase incentives on consumers
Opt-back	Consumers can opt back to a legacy or shadow quantity	The Lines Company applies the lesser of the actual billed demand or the assessed consumer profile demand	• Cost and complexity associated with running two systems
Guaranteed price	A wash up is calculated monthly to ensure consumers pay no more than an agreed amount (for example, charges under legacy pricing) for a limited period		• This is usually only provided for a limited time, and can be phased out over time • May be difficult to forecast revenue
New prices lower for most consumers	The new cost reflective pricing would be set to ensure that most consumers (ie 90%) are better off compared to legacy pricing. This will incentivise people to shift to new prices to reduce their bills.		• Requires careful management of total revenues and uptake of new pricing.

Source: ENA

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Appendix B: Survey of ToU consumption offerings

The following summary of distributors' ToU consumption pricing was compiled by a retailer and highlights the opportunity for alignment.

Mass market TOU Pricing as at 1/4/16	Weekday - trading period Starting	Weekend - trading period Starting
	0000 0030 0100 0130 0200 0230 0300 0330 0400 0430 0500 0530 0600 0630 0700 0730 0800 0830 0900 0930 1000 1030 1100 1130 1200 1230 1300 1330 1400 1430 1500 1530 1600 1630 1700 1730 1800 1830 1900 1930 2000 2030 2100 2130 2200 2230 2300 2330	0000 0030 0100 0130 0200 0230 0300 0330 0400 0430 0500 0530 0600 0630 0700 0730 0800 0830 0900 0930 1000 1030 1100 1130 1200 1230 1300 1330 1400 1430 1500 1530 1600 1630 1700 1730 1800 1830 1900 1930 2000 2030 2100 2130 2200 2230 2300 2330
Trading period (half hour ending)	1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48	1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48
3 RATE for Anytime load		
WEL Networks		
Peak (workdays) 0700 - 0930; 1730 - 2000		
Off Peak (workdays, public holidays**, weekends) 2200 - 0700		
Shoulder Peak (workdays, public holidays**, weekends) 0930 - 1730; 2000 - 2200		
Controlled (separately metered)		
** includes Waikato Regional holidays only		
Counties Power		
Peak (weekdays) 0700 - 0830; 1730 - 2030		
Off Peak 2030 - 0700		
Shoulder (weekday 0830 - 1730, weekends 0700 - 2030)		
Controlled (separately metered)		
Electra Triple Saver		
Peak 0700 - 1100; 1700 - 2100		
Night (lowest rate) 2300 - 0700		
Off Peak (middle rate) 1100 - 1700; 2100 - 2300		
Top Energy		
General Advanced Peak 0700 - 0830; 1730 - 2000		
General Advanced Off Peak 2300 - 0700		
General Advanced Shoulder Peak 0930 - 1730; 2000-2300		
Waipa		
Peak 0700 - 1000; 1600 - 2100		
Off Peak 2300 - 0700		
Shoulder Peak 1000 - 1600; 2100 - 2300		
2 RATE for Anytime load		
Vector		
Peak (workdays, public holidays) 0700 - 1100; 1700 - 2100		
Off Peak (workdays and public holidays 1100 - 1700; 2100 - 0700, weekends)		
Tariff rates include controlled load		
Unison Networks		
On Peak (weekdays which include public holidays) 0700 - 1100; 1700 - 2100		
Off Peak (weekdays which include public holidays 1100 - 1700; 2100 - 0700, weekends)		
Controlled (separately metered)		

Appendix C: Regional coincident peak period analysis

UNI

	Period start time																													
Month	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	11:30	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	Overall
January																														0%
February																														0%
March																														0%
April																														0%
May		0%	0%	0%																	0%	0%	0%	2%	0%	0%	0%	0%		2%
June		2%	2%	0%																	2%	15%	12%	8%	0%	0%	3%	0%		43%
July		3%	2%	2%																	0%	2%	2%	3%	2%	2%	2%	2%		20%
August		3%	2%	0%																	0%	5%	8%	7%	7%	2%	0%	0%		33%
September		0%	0%	0%																	0%	0%	0%	2%	0%	0%	0%	0%		2%
October																														0%
November																														0%
December																														0%
Overall	0%	8%	5%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	22%	22%	22%	8%	3%	5%	2%	0%	100%

LNI

	Period start time																													
Month	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	11:30	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	Overall
January																														0%
February																														0%
March																														0%
April																														0%
May	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%									0%	0%	0%	3%	2%	1%	0%	0%	0%	0%		7%
June	0%	1%	2%	0%	0%	0%	0%	0%	0%	0%									0%	0%	3%	9%	6%	3%	2%	1%	0%	0%		27%
July	0%	2%	2%	1%	0%	0%	0%	0%	0%	0%									0%	0%	2%	9%	9%	6%	2%	1%	1%	0%		34%
August	1%	3%	2%	1%	1%	1%	1%	0%	0%	0%									0%	1%	1%	3%	7%	4%	1%	1%	1%	1%		28%
September	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%									0%	0%	0%	0%	1%	1%	0%	0%	0%	0%		3%
October																														0%
November																														0%
December																														0%
Overall	1%	6%	6%	2%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	6%	24%	25%	15%	5%	3%	2%	1%	0%	100%

USI

	Period start time																													
Month	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	11:30	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	Overall
January																														0%
February																														0%
March																														0%
April																														0%
May	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	4%
June	0%	2%	2%	1%	2%	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	5%	3%	1%	0%	0%	0%	0%	0%	25%
July	0%	3%	2%	3%	3%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	5%	5%	1%	1%	0%	0%	0%	0%	29%
August	1%	5%	3%	3%	2%	2%	1%	1%	1%	1%	1%	1%	0%	1%	0%	0%	0%	0%	0%	1%	1%	2%	5%	4%	2%	1%	1%	1%	0%	40%
September	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
October	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
November	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
December																														0%
Overall	1%	12%	8%	7%	7%	5%	3%	2%	2%	1%	1%	1%	1%	1%	1%	1%	0%	0%	1%	1%	4%	12%	13%	6%	3%	2%	1%	1%	0%	100%

LSI

	Period start time																													
Month	07:00	07:30	08:00	08:30	09:00	09:30	10:00	10:30	11:00	11:30	12:00	12:30	13:00	13:30	14:00	14:30	15:00	15:30	16:00	16:30	17:00	17:30	18:00	18:30	19:00	19:30	20:00	20:30	21:00	Overall
January	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
February	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%
March	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
April	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	4%
May	0%	0%	1%	0%	0%	0%	1%	1%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	2%	1%	0%	0%	0%	0%	0%	13%
June	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	8%
July	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	1%	1%	0%	0%	0%	0%	0%	5%
August	2%	3%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	2%	2%	1%	1%	1%	0%	37%
September	1%	3%	4%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	17%
October	0%	1%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%
November	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%
December	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%
Overall	3%	10%	12%	9%	5%	4%	4%	3%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	4%	9%	8%	5%	4%	2%	2%	1%	0%	100%

Source: ENA analysis of Transpower RCPD data

Appendix D: Regulatory compliance

Background

Electricity distribution pricing is regulated by:

- the EA under the Electricity Industry Act 2010 (the EIA) and other regulations
- the Commerce Commission (Commission) under Part 4 of the Commerce Act 1986 (Part 4).

Electricity Authority Regulation

The EIA sets out the policy framework for the regulation of the electricity industry by the EA. The EA's statutory objective under the EIA is:

> *"To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers"*

The EA has a broad range of powers under the EIA, including:

- making and administering the Electricity Industry Participation Code (the code) that sets out the rules and regulations governing the operation of the market
- monitoring, investigation and enforcement of compliance with the EIA, regulations and code
- undertaking market facilitation, including providing education, guidelines, information and model arrangements
- industry and market monitoring on any matter relating to the industry.

Commerce Commission Regulation

Part 4 sets out the legislative framework for the economic regulation of services where there is little or no competition, and includes specific regulations relating to electricity distribution businesses.

The Commission has a range of regulatory tools under Part 4, including broad powers to require disclosure of information from all distributors (information disclosures), and more specific powers to set allowable revenues under a default price-quality path (DPPs) or alternatively under a customised price-quality path (CPP). The Commission has developed input methodologies (IMs) that set out detailed regulatory methodologies and rules relating to each of these three regulatory tools.

Seventeen distributors are subject to price regulation under either a DPP or CPP. The remaining 12 distributors are exempt from price-quality regulation as they meet the 'consumer-owned' exemption criteria under the Part 4. All distributors are subject to pricing regulation.

Pricing Principles

The EA is responsible for setting distribution pricing methodologies under the EIA[59]. The EA has developed a set of economic pricing principles which distributors must consider when developing their pricing methodologies. The pricing principles broadly set out that pricing should:

- reflect the costs of service provision
- signal efficient use of and investment in the network
- be responsive to consumer-specific circumstances (i.e. by discouraging uneconomic bypass of the network, allowing negotiation on price and quality matters, and encouraging network alternatives)
- be transparent and stable
- have regard to transaction costs and retail competition.

Electricity Authority pricing principles

(a) Prices are to signal the economic costs of service provision, by: (i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation; (ii) having regard, to the extent practicable, to the level of available service capacity; and (iii) signalling, to the extent practicable, the impact of additional usage on future investment costs.
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to: (i) discourage uneconomic bypass; (ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and (iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (eg distributed generation or demand response) and technology innovation.
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.
(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

Source: ENA

It is noted that the EA is currently in the process of reviewing these pricing principles.

[59] Section 52T(I)(6) of Part 4

Pricing Disclosures

Pricing disclosure is an area where the two regulators have shared interests and roles. Below is a summary of the disclosure requirements and guidelines that are relevant to distributors when disclosing, notifying, and publishing any future pricing structures.

Pricing Methodologies

Distributors are required to publicly disclose their pricing methodology under section 2.4 of the ID requirements, which broadly must describe the approach used to calculate prices. It is likely that most distributors will need to amend their pricing methodologies to comply with these requirements when introducing future pricing structures.

Pricing methodologies must be disclosed within 20 business days of any change in the methodology taking effect.

The EA has also supplemented these requirements with information disclosure guidelines. These were considered useful in providing guidance on how to show that the pricing principles had been adequately considered in pricing methodologies. A full copy of the pricing principles and guidelines can be found on the EA's website: https://www.ea.govt.nz/dmsdocument/1944

Price notifications

Regulations and guidelines govern how distributors should notify consumers of any price change.

Section 2.4 of the IDs requires distributors to, always, publicly disclose their prices expressed in a manner that enables consumers to determine the consumer group(s) and prices applicable to them. The transmission component of prices, the estimated number of consumers for each price, the date the price was introduced, and the price payable immediately prior to this must also be disclosed.

Any changes to standard prices must be publicly disclosed 20 business days before the change takes effect and must be notified to consumers either:

- in writing to the consumer, or
- in the news section of two separate newspapers or in online media accessible using the internet and widely read by consumers.

The EA has also recently provided guidance for distributors and retailers on their communications to consumers and the media concerning price changes. The guidelines suggest that:

- accurate and meaningful information is available about price changes so that interested consumers are informed of the reasons for those changes
- consumers receive information on the extent to which changes in transmission and distribution charges are reflected in their prices
- distributors' prices are provided to retailers in a form that is useful for price construction and with sufficient supporting information
- information about price changes is provided to consumers in a timely and accessible manner

- public statements from industry spokes people to consumers and media on price changes are accurate, precise and made in good faith, and avoid the possible confusion that can be caused by using different approaches to describing price changes
- The EA has timely access to price change notifications and public comments.

A copy of the communications guidelines can be found on the EA's website: https://www.ea.govt.nz/dmsdocument/19333

Consultation

Clause 12A.7(2) of the code requires distributors to consult with retailers in respect of changes to distribution pricing structures that materially affect one or more retailers or consumers.

The EA has also developed "guidelines for consulting on distributor tariff structure changes",[60] which provide guidance on the scope, approach, and process for such consultations. The EA's objective is effective consultation between distributors and retailers during the early stages of the price change process.

Under the EA's Model Use of System Agreement (and proposed Default Use of System Agreement), distributors must comply with the guidelines, including by implementing the good consultation practices set out in the guidelines.

The guidelines consist of three elements that set out:

- the scope of the consultation process
- consultation principles
- good practice guidance.

The scope says that consultation should take place on any changes to pricing structures that materially affect retailers or consumers, consistent with clause 12A.7(2) of the code. Without limiting this, several examples are provided on when consultation should apply. These include:

- a change in the eligibility for one or more of the distributor's pricing structures
- the addition or removal of a pricing band.

Several key areas covered in the guidelines include:

- Consultation definitions and approaches: It provides that consultation is not negotiation and does not require agreement, but the distributor must approach consultation with an open mind in a clear and transparent manner.
- The form of consultation: There is no universal requirement as to the form of consultation (e.g. written, oral, presentation etc.). However, consultation must provide relevant information at appropriate stages and allow for adequate expression of views.

[60] Guidelines for consulting on distributor tariff structure changes: http://www.ea.govt.nz/document/16898/download/our-work/programmes/market/consumer-rights-policy/model-arrangements/distribution-tariff/

- Consultation process and timeframe: Distributors are free to determine when the consultation process will commence, but it is suggested that consultation must end before obtaining internal approvals and prior to normal retailer price change notification periods. The guidance suggests that retailers need to be involved early in the development of pricing methodologies. The guidance sets out that consultation should involve a draft proposal, consideration of feedback, and then a decision. Sufficient time and genuine effort must be made as part of consultation. Distributors should also have regard to minimum regulatory requirements relating to notification periods and the frequency of tariff changes.
- Information provided: Sufficient information must be provided for retailers to make “intelligent and useful” responses and reference should be made to the EA’s pricing principles and the extent to which the price change is consistent with them.

Part 4 regulation

Background

Changes in pricing structures and in billable quantities that arise from transitioning to future types of pricing is relevant to price-quality regulation under a DPP and CPP.

Apart from Orion, non-exempt distributors are subject to price regulation under DPP. These distributors must set distribution prices such that Notional Revenue (NR) is less than or equal to Allowable Notional Revenue (ANR).

- NR is calculated regarding the sum of published unit prices multiplied by billed quantities that are lagged two pricing years.
- ANR is calculated regarding the sum of the previous pricing year’s prices multiplied by lagged quantities plus the difference between NR and ANR for the previous year, all multiplied by CPI inflation and an X factor.

Compliance with the price path is solely determined on the level of the distribution prices component set by the distributor. Prices that recover pass through and recoverable costs (eg rates, levies, Transpower charges passed on by the distributor, and regulatory adjustments and allowances) are now captured in a rolling annual pass through balance (PTB). This calculates the cumulative difference between pass through and recoverable costs and revenue received through pass-through prices, with a time value of money adjustment. There is no absolute compliance requirement relating to the balance amount.

The quantities used to determine the pass-through prices must be based on reasonable forecasts of quantities (using information known at the time the prices are set).

Compliance issues

A future pricing option that is introduced voluntarily, where consumers self-select into the pricing option, is less likely to cause compliance issues under a weighted average price cap when transitioning to future types of pricing. This is because lagged quantities will progressively be introduced into the compliance formula as consumers transfer to the new types of pricing.

However, if existing consumers are assigned to new types of pricing by the distributor (ie, a mandatory transition), then this will raise several compliance considerations. The calculation of NR and ANR will need to be amended to reflect the restructure of prices, for example:

- historical lagged billing quantities (ie Q_{t-2}) will need to be re-based to align to the quantities specified in the new pricing structures (ie, from kWh to kW under a demand charge)
- estimates may need to be used where billing data for new prices is not available in Q_{t-2}

Forecasts of new billing quantities may also need to be developed when determining pass-through prices. This may be difficult if AMI meter data is unavailable or where the consumer response to a new pricing option is uncertainty.

Clause 8.7-8.10 of the DPP provides guidance on how to adjust the quantities used in the calculation of ANR and NR when a restructure of prices is made.

We note the Commission is reconsidering these regulatory compliance structures, and has proposed a revenue cap, which would potential simplify (or potentially eliminate) some of the issues described above. Further work on the implications of moving to cost-reflective pricing under a revenue cap will be required if this proposal progresses.

Low Fixed Charge Regulations

Background

The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (LFC Regulations) require retailers to offer domestic consumers a pricing option with a fixed charge not exceeding 30 cents per day (excluding GST and after prompt payment discounts).

To facilitate retailers meeting these obligations, distributors are required to offer a similar pricing option to domestic consumers (whether directly to consumers or through the retailer). The distributor’s daily fixed charge must not exceed 15 cents per day.

When combined with other variable charge components, the LFC pricing option (both the retailer’s and distributor’s charges) should be set so that consumers taking up the option are no worse off than other domestic consumers on non-LFC prices using 8,000 kWh per annum (9,000 kWh in the lower South Island).

Traditionally, distributors and retailers have adopted kWh based charges as the variable charge component referred to in these regulations – which is consistent with the specification of the cross-over thresholds (8000 kWh and 9000 kWh) included in the LFC regulations.

Compliance

There has been uncertainty as to whether demand and capacity pricing would be “fixed charges” or “variable charges” under the LFC. In response to requests for clarification, the EA has published a set of guidelines (the

LFC guidelines)[61]. The LFC guidelines have direct implications for the types of pricing examined in these guidelines and have been considered.

Regarding the pricing types considered in this report, the LFC Guidelines make the following clarification as to which prices would be considered variable and therefore not restricted by the LFC Regulations:

- consumption prices, including ToU consumption prices, are variable. This is because consumption charges relate to the amount of electricity consumed over time.
- demand charges, including Customer Demand and Network Demand, are variable. The EA explains that demand charges are based on the amount of electricity consumed during one or more identified measurement periods.
- capacity charges are variable, if the consumer can change their level of capacity. The EA states that:

> *A capacity charge that varies according to the amount of electricity a consumer expects to consume is a variable charge. So, capacity charges are variable – provided the consumer can change its capacity at a reasonable cost and in a reasonable period, and so change the amount of the capacity charge that will apply. If in practice the consumer is unable to affect the amount of a capacity charge, then that charge would be a fixed charge.*

There are also restrictions in the LFC regulations on tiered or stepped variable charges.

We note that it is up to each distributor to review the LFC guidelines and weigh up the regulatory risk of any pricing option. The EA as the enforcer of the LFC regulations has clearly set out its view as to how the regulation should be interpreted. Risks associated with legal challenges to that position, political response and how subsequent consumers receive price changes are matters for each individual distributor to evaluate.

Pricing of distributed generation

Part 6 of the code deals with the connection of distributed generation to electricity distribution networks. Schedule 6.4 requires distributors to set prices based on reasonable costs, including consideration of any identifiable avoided costs:

> *"Charges [are] to be based on recovery of reasonable costs incurred by [the] distributor to connect the distributed generator and to comply with connection and operation standards within the network, and must include consideration of any identifiable avoided or avoidable costs" - clause 2 of schedule 6.4*

Additionally, clause 2(a) of schedule 6.4 sets a price cap at the incremental cost of connecting DG net of any avoided costs:

> *"…connection charges in respect of distributed generation must not exceed the incremental cost of providing connection services to the distributed connection. To avoid doubt incremental cost is net of*

[61] Electricity Authority (August 2016) *Variable charges under the Low Fixed Charge Regulations – Guidelines* available at http://www.ea.govt.nz/development/work-programme/evolving-tech-business/distribution-pricing-review/development/guidelines-for-low-fixed-charge-regulations/

transmission and distribution costs that an efficient market operation service provider would be able to avoid as a result of the connection of the distributed generation"

Further guidance over how to calculate avoided costs is provided in clause 2(b) of schedule 6.4, which states that avoided costs:

"…must be estimated with reference to reasonable estimates of how the distributor's capital investment decisions and operating costs would differ, in the future, with and without the generation"

While these requirements apply at the time of release of this report, we note the EA is proposing to remove schedule 6.4 from part 6 the code, as it believes the current pricing principles are driving inefficient investment in both generation and network assets.

It is the ENA's assumption that the DG pricing principles will be rescinded (as proposed). However, we recommend distributors monitor these developments when assessing whether new cost-reflective pricing structures are compliant with part 6. We note that the EA has clarified that Part 6 of the code does not apply to consumption charges, only charges that apply to distributed generation (eg; the export of electricity on to the network).

Changes to EIEP codes

Part 12A of the code requires distributors that do not send accounts directly to consumers to:

- exchange price information between themselves and retailers based on electricity information exchange protocol (EIEP) 12 as incorporated by reference to the code
- to use standardised price formats when assigning pricing codes to different consumers.

Distributors will need to ensure any new pricing codes are compliant with EIEP12. The industry may also need to consider whether EIEP12 needs to be updated for new distribution pricing structures.

Further regulation

Section 113 of the EIA identifies several pricing related issues on which the Minister of Energy can recommend further regulation. Broadly, the areas covered by section 113 relate to:

- regulating the types of pricing structures and fixed charges that must, or may be, offered to domestic consumers, including providing low fixed charge types of pricing to consumers who use less than a prescribed amount of electricity
- enabling the protection of rural consumers from unfair rates of change in the prices charged to them

Appendix E: TLC Pricing Review

The following provides a summary of the lessons learned from the 2016/17 independent review of TLC's pricing methodology undertaken by Roger Sutton and Lynne Taylor.

Context

TLC sought an independent review of its pricing methodology with an overarching objective to understand how a pricing methodology can be applied to achieve optimum equity, simplicity, and transparency for the customers on TLC's network.

TLC's supply area is characterised by sparsely populated areas with small urban communities. The network has a high proportion of tenanted or holiday homes and a mix of industry, dairy and other seasonal loads influenced by tourism and holiday demand. There is limited growth in residential and commercial electricity demand – with a high proportion of residential connections qualifying for low user charges. There is some potential for large customer agricultural and industrial development, particularly in the north.

Review approach

The independent review evaluated the current pricing methodology and possible refinements and alternatives against a number of methodology and implementaion criteria, which align with the Electricity Authority's electricity distribution pricing principles.

Current pricing approach

TLC's current pricing approach has some unique features including many customer groups; demand charging for mass market customers; direct billing and metering; and charges for vacant properties and transformers servicing 3 or less connections.

Approximately half of TLC's distribution costs are recovered via fixed charges, charged on a capacity basis for standard customers and a monthly fee for low use customers. The remaining distribution costs and all transmission costs are recovered via variable charges, charged on a peak demand basis, measured during periods of load control for standard customers, and a peak capacity basis for major customers.

For the variable demand charge, peak demand is measured during periods of load control. TLC's load control periods are aligned to Transpower's Regional Coincident Peak Demand periods, as a proxy for network peaks. These typically occur during winter evenings. Some regions across TLC's network also have high summer peaks due to dairy and industrial load.

The kW load quantity is calculated once a year, using each customer's six highest peaks from the past year, generally recorded during the previous winter. At the beginning of each pricing year, pricing notifications are sent to customers advising them of their kW load quantity. The variable charge is then recovered in 12 equal monthly instalments, from April to March, using the kW measure from the prior year.

Stakeholder views

Stakeholder consultation revealed that community leaders and customers are concerned about the impact of TLC's pricing on the community and consider the current pricing methodology is too complex and difficult to understand. In particular customers have particular issues with the unpredictability and volatility of the variable demand charges, and the inability to respond to the pricing signal in a timely way due to the lag between peak demand measurement and billing. Some customers have made sub-optimal investment and usage decisions due to pricing complexity, while others have made significant savings. Overall TLC's current pricing methodology is perceived as having a negative impact on the welfare of the community.

Review findings

The review, which focussed on the pricing methodology applied to mass market customers, found that while the current pricing methodology rates well on many of the evaluation criteria in principle, in practice it does not score as well.

Variable (demand) charges

TLC's demand pricing approach rewards those customers with controlled hot water supply, who can move non-controlled demand outside of load control periods, and who have invested in alternative supply sources which are able to be used during load control periods. However, the review found that many customers have not been able to respond to the price signals in this way, and as a result have incurred high demand charges.

Some customers have made investments (such as in diesel generators) or changed their demand profiles enabling them to successfully reduce their peak demand and lines charges. Other customers have made investments (such as in solar or gas hot water heating) which have had little effect, or have reduced consumption in periods with no load control, with no reduction in lines charges.

While TLC has invested considerable effort in explaining its pricing methodology, many customers do not understand the demand charging approach very well. This has had a negative impact on customer utility and added cost to the organisation.

Balance between fixed and variable charges

The review found that customers with low peak demand, and therefore low demand charges, are not contributing sufficiently to TLC's fixed costs. In addition, customers are unduly penalised for consumption at peak times as the unit demand charges significantly exceed the estimated long run marginal costs of the network. This is particularly acute for low use customers with very high variable charges due to the approach adopted to complying with the low user fixed charge regulations.

Accordingly, the review concluded that as TLC's cost structure is largely fixed for the near future, the variable component of charges could be reduced, subject to the requirements of the Low User regulations. Higher fixed charges were also recommended for holiday homes to improve cost recovery.

Customer groups

The review questioned whether multiple customer groups is appropriate for TLC's network given the small customer base and lack of significant urban areas. The highly disaggregated approach requires many assumptions and judgements and prices do not fully align with underlying cost allocations which can be volatile. Other options for reducing complexity were also recommended such as the removal of the dedicated transformer and vacant property charges.

TOU recommendation

The review recommended replacing the variable demand charge with a variable TOU charge, incorporating higher peak prices and lower shoulder and off-peak prices. This form of pricing retains a peak signal, but implements it in a way that is easier for customers to understand and respond to.

Although a TOU peak signal is weaker than the demand pricing approach, TLC is largely focused on maintaining and renewing the current network. Some network constraints may emerge in the north during the planning period, however the review noted that customer specific investments are expected to address a significant portion of the additional forecast load. In addition, the complexity in the current approach adds cost to the organisation which offsets the efficiency gains sought.

The review concluded that TLC is expected to - with continued use of load control at peak times - accommodate a more balanced pricing structure which is more simple and transparent for customers, without significantly compromising its equity and efficiency objectives.

GLOSSARY

Term	Meaning
Advanced Meter	Meters with half-hour, real-time, remote read functionality
Booked demand pricing	Pricing that reflects the predefined customer maximum demand.
Controlled load	Distributor intervention to reduce load at times of peak demand
Cost-reflective pricing	Pricing that reflects the cost of delivering the service.
Customer demand pricing	Pricing that reflects anytime customer peak demand
Demand-side response	Consumer-led demand initiative to shift or reduce consumption
DG	Distributed Generation - generation that is connected directly to a distribution network rather than to the national transmission grid
DPWG	ENA's Distribution Pricing Working Group
EA	Electricity Authority
EIA	Electricity Industry Act 2010
Electricity Industry Participation Code	The Code – rules which govern the operation of the electricity market, administered by the Electricity Authority
ENA	Electricity Networks Association
EDB	Electricity Distribution Business or Distributor
EV	Electric Vehicle
GW	Gigawatt
GXP	Grid Exit Point
GXP Pricing	Distribution prices are billed to the retailer based on electricity volumes measured at Grid Exit Points.
ICP	An Installation Control Point (ICP) is a physical point of connection on a local network or an embedded network that the distributor nominates as the point at which a retailer will be deemed to supply electricity to a consumer.
ICP Pricing	Distribution prices are billed to the retailer based on electricity volumes measured at the meters of individual ICPs.
kVA	Kilo Volt Amperes. A unit of measurement of apparent electrical power. For network pricing, it is often used to measure the amount of the capacity required/utilised by a connection.
kW	Kilowatt. A unit of measurement of electrical power. For network pricing, it is often used to measure the amount of consumer load.
kWh	Kilowatt hour

LRMC	Long run marginal cost
LFC Regulations	The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (Regulations). These regulations require distributors and retailers to make available to residential consumers a pricing option with low fixed charges limited to 15c/day for distributors and 30c/day for retailers.
MW	Megawatt
Network Demand Pricing	Pricing that reflects network peak demand
PV	Solar photovoltaic generation
Service-based pricing	The EA defines this occurring when the cost of a service is charged only to those consumers receiving the benefit of the service. It also means consumers pay higher prices for higher service levels and lower prices for lower service levels.
Smart meter	Advanced meter
SSDG	Small scale distributed generation
ToU	Time of Use