Orion delivery pricing

Consultation and discussion paper

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1. Introduction

Electricity delivery pricing[1] is developing in response to challenges on a number of fronts.

Customers are increasingly considering investment in technologies such as solar panels (PV), batteries, electric vehicles (EV) and home energy management systems. The way distributors price influences those investment decisions, but it also determines how much different types of customers pay relative to each other. Critical for us in consideration of any pricing changes is this balance between what is efficient, and what is fair.

The Electricity Authority is encouraging a move toward service based and cost reflective arrangements to address these sorts of issues, while, at the same time, regulations significantly prevent such movements and stakeholders are calling for more standardised and simplified approaches.

We consider that an interconnected network will continue to provide a vital service through and after technology changes, but the shape of that network and the presentation of costs via our pricing is likely to change. We are not yet in a position to see what the final outcome might be, or the extent to which our business model might change.

With this consultation we are looking to introduce some initial changes that take a first step toward addressing some of the issues and challenges presented by new technologies, and also seek feedback on our future direction to help guide our subsequent reform.

This consultation is focused primarily on pricing for our general connection category, which generates around 80% of our revenue. Within that group there is particular emphasis on residential customers. However, we are proposing some changes to our major customer pricing to better reflect costs at the smaller end of the category, allowing us to extend the range where customers are able to elect which category to be in.

As well as this stakeholder consultation targeted at retailers and consultants[2], we anticipate engaging in some form of customer consultation. The exact form of this has yet to be determined, but we will be guided by the protocol jointly established by the Electricity Networks Association and the Electricity Retailers Association of New Zealand.

This is a fairly long paper. Not all stakeholders are equally interested in all aspects of pricing, or have equal resources to devote to the task. If your resources are limited, or your focus is on the short term impacts, you may wish to concentrate on just sections 6.1 and 6.2 of this paper.

[1] Our prices cover the cost of both transmission and distribution. We refer to the combined service as delivery.

[2] This paper assumes the reader has a good knowledge and understanding of the regulatory framework and settings in New Zealand, the Electricity Authority's pricing principles and information disclosure guidelines (and the general principles of network economics), and Orion's current pricing methodology and other pricing disclosures, including the 'road map' we published in our February 2017 pricing methodology.

2. Customers

Front and centre of our thinking is the customer, who in this context is the end user or consumer of electricity[3], and more specifically our distribution service. Fundamentally, if pricing isn't in the long term interests of customers, it doesn't work for us.

There is a significant body of research that indicates that, for customers, there is generally a low level of interest in electricity supply, except when there's an outage.

UMR recently carried out some research via focus groups – of residential customers – for the Electricity Networks Association (ENA) on the general topic of distribution pricing and pricing options. We do not reproduce all the findings here, but to us the key ones are that customers, as a group, want pricing arrangements that are:

- Fair
- Simple and understandable
- Provide incentives
- Enable choice

The ENA has also recently produced a guidance paper on distribution pricing (building on its November 2016 discussion paper), which listed desirable attributes of distribution pricing as follows:

- Efficient
- Actionable and simple
- Durable and flexible
- Stable and predictable
- Support retail competition.

The guidance paper notes there are trade-offs between the attributes.

Notwithstanding this research and analysis, on the Orion network there is, in fact, already significant customer involvement in the supply chain, at least partly reflecting our current pricing, which takes three main forms with the first two being by far the most material:[4]

1. Customers who choose to have their storage heating (usually a hot water cylinder) peak load controlled (about 90,500, or 45% of customers),
2. Customers who choose to have their storage heating only happen at night (about 73,000, or 37% of customers), and

[3] Throughout this document we generally, unless the context requires otherwise, use the word 'customer' to refer to the end user of the delivery service.
[4] At least for residential and small business customers these are the main forms. There are a number of variations, for example some customers with night-rate water heating have an afternoon 'boost' for their water heating, while others have bypass switches that mean they can (subject to peak load control) heat water during the day, paying the higher price. Major customers also respond to our price signals in various ways, but that is not discussed in this paper.

3. Customers who make choices about the timing of other activities, such as when washing machines and dishwashers are turned on (available to most of the customers in the second group).

We are not sure how well customers would be able to say with certainty which of the first two arrangements applies to them, but the result has been and is very effective. We estimate that our upstream network capacity (including to some extent transmission capacity) is around 130MW (20%) less than it would have to be were these arrangements not in place. As a result our annual revenue requirement is around 10% lower that it would otherwise be. Put another way, a significant amount of investment, which is effectively funded by customers, would be required if this response was not available.

We further note that this response works because it is coordinated.

In terms of the UMR research findings, the current arrangements appear to be simple and understandable, provide incentives and enable choice. Whether they are fair is somewhat harder to judge. In terms of the ENA guidance we would judge there is reasonable alignment overall, with the key concern being the potential inefficiency associated with our volume charges.

For us the lessons from the status quo are two-fold:

- simple customer propositions can be very effective, and so a key question is whether our arrangements with our contractual counterparties (retailers) align well with such propositions, and
- the value of what is currently in place and working needs to be acknowledged when we consider changes.

On that note we observe that a number of retailers no longer offer a lower ‘inclusive’ rate for customers on the first arrangement above. We understand the reasons for that, but it does tend to mean that the arrangement – which is central to our network planning and operation, and which keeps bills lower – could be at risk.

3. Current issues

Within the context set out above, and when considering changes to pricing structures, there are two main issues that we face now: variabilisation of costs and peak charging complexity. These issues are expanded upon below.

3.1 Variable or volume-based recovery of fixed costs

Our existing pricing for general connections recovers a significant proportion of our fixed costs via variable (or volume-based) charges. We don't currently apply any fixed charges for general connections. In addition, electricity retailers are generally repackaging our peak demand pricing as volume based pricing, averaging the cost out across broad periods throughout the year.

We have maintained this structure for many years, and while it has some undesirable features,[5] we believe it has overall served customers well, particularly, as discussed above, those that have invested in storage hot water systems that enable peak load management and / or deferral of energy consumption to the night.

However, new technologies provide some challenges to our approach:

- Solar photovoltaics (PV) reduce volumes (and associated revenue as PV generation occurs at times when our volume price is high) but do not reduce our fixed or peak related delivery costs. Customers installing PV thus reduce the extent to which they contribute toward covering our costs. These costs must still be met and so the burden is shifted to other customers. As well as this wealth transfer effect, investment in PV may be greater than is optimal from a New Zealand Incorporated perspective particularly given our high level of existing and prospective generation from other renewables.

- Battery storage may allow 'gaming' of the volume price differences, in particular by encouraging storage of PV generation that might otherwise be exported. On the other hand batteries may support further flattening of load on our highest demand days. It all depends on how these devices are coordinated.

- Electric vehicles will, other things equal, often be charged at night, but this may create problems if they all begin charging around the same time. On the other hand, EVs stack up financially – compared with petrol or diesel vehicles – on pretty much any distribution pricing basis.

[5] For example, to some extent it:

- Over-rewards energy efficiency – customers that invest in things like low energy lighting and insulation receive a benefit that is greater than our cost savings.
- Promotes use of alternatives – in situations where an electric solution might be the most efficient (eg a heat pump for space heating), high volume pricing can promote alternatives with a higher true cost.
- Result in over-charging high users – customers that use more energy, perhaps because they have a large family, inefficient appliances and/or poor insulation, tend to pay too much. They contribute more than their share toward fixed costs, and are sometimes the least able to afford this.

On the other hand, and regarding the first two points in particular, these sorts of investments probably also reduce demand at peak times, so there is some offsetting benefit.

- Home energy management systems (HEMS) may facilitate demand response which, depending on the structure of pricing and how the systems respond to it, can be either good, bad or neutral from a network perspective.

Of these challenges, PV is the most immediate and, with current pricing, has the most unambiguous negative effect from the perspective of efficiency. Over time it will also lead to customers without PV paying more, other things being equal, and this is probably seen as unfair.

3.2 Peak charge complexity

We reflect our peak related costs with a peak charge. Although this appears to align with the direction that the Electricity Authority is encouraging distributors to move, it has proven challenging for retailers to reflect in residential and SME pricing.

The peaks that drive our costs occur only in winter, and we have observed that it is unpalatable, at least from a residential customer perspective, to either charge this cost only in winter (because the seasonal jump in power bills would be too great), or spread the cost over the following year (because changes in consumption after winter can occur as tenants or kids leaving home and would not be reflected in bills for more than a year).

Also, a customer's average contribution to our peak cannot be established until all peaks have occurred. These Peaks are weather dependent, and some winter months have many peaks and others have very few or even none. This makes it necessary to either:

- Estimate a customer's contribution and then apply a wash up (which is difficult in a residential market segment, with customer changes and retail switching), or

- Apply delayed charging with updates applying after completion of the ~4 winter months (which exacerbates the delay issue noted above, so that changes in peak contribution can take up to 16 months to be reflected in charges).

Further, from a retail perspective, our peak charging creates a number of issues which are difficult to address in a residential setting:

- Uncertainty – retailers must set prices before knowing the magnitude of our peak charge. This creates a 'rebundling' risk.

- Residual liability – retailers face the costs associated with the winter based peak contribution of their customer base. Where a customer disconnects or shifts to another retailer after winter, the liability remains with the first retailer until the end of the year.

- Reflecting costs – retailers often want to show that they are reflecting network costs, but there are a number of different ways that peak charges can be reflected, and different customer mixes can also drive different results.

- Complexity – residential customers often don’t understand the pricing and this results in queries and sometimes complaints, increasing costs for retailers. We note The Lines Company’s experience with this sort of pricing at customer level over a number of years, which, according to two separate reviews, has been found to be too complex and led to perverse outcomes, while creating anxiety and confusion along the way.

Q1. Have we captured the problems with peak pricing? How should we weight these against the alignment of peak pricing with other pricing principles?

4. Further background

4.1 How we conceive of our network and our costs

Electricity networks are complex interconnected systems. No two paths to points of connection will involve exactly the same quantity or type of assets, or have exactly the same attributes in terms of capacity, reliability etc. Moreover, the paths may change over time. Increasingly, the paths are two-way.

From a pricing perspective, we conceive of the network in a much more simplified way. For example (and including for reference the indicative amounts of annual revenue associated with the assets):

- Transpower - transmission, ($70m)
- Orion -
    - sub-transmission, ($54m)
    - high voltage 11kV distribution, ($65) and
    - low voltage distribution ($42m).

We further, in general, assume that assets used to supply customers in any connection category, and the way we manage those assets, is sufficiently similar that the service provided is essentially the same for all customers within the category, and hence the prices for the service are the same. In other words there is a strong ‘common quality’ dimension to our service.

The costs associated with each part of the network vary somewhat in relative value, but more importantly in terms of what drives them.

The aggregate demand (across all connections) on the network at times of coincident maximum demand (CMD) tends to drive investment in the transmission and sub-transmission systems and much of our high voltage network. Separately, the anytime maximum demand (AMD) of individual connections tends to drive investment in the low voltage network. Another way to think about this is that assets close to the customer’s connection need to be sized to support each customers peak demand (AMD), while those further up the network can be sized to support the diversified peak demand (CMD). This distinction is important for two reasons:

- the two numbers are different – a customer that has a significant load (and a high AMD) might have a relatively low contribution to CMD – so one measure is not a good substitute for the other, and
- reducing AMD at a particular connection does not of itself reduce any costs in any part of the network.

The distinction is reflected in the way the various levels of the network are planned and built. Thinking of a typical residential subdivision:

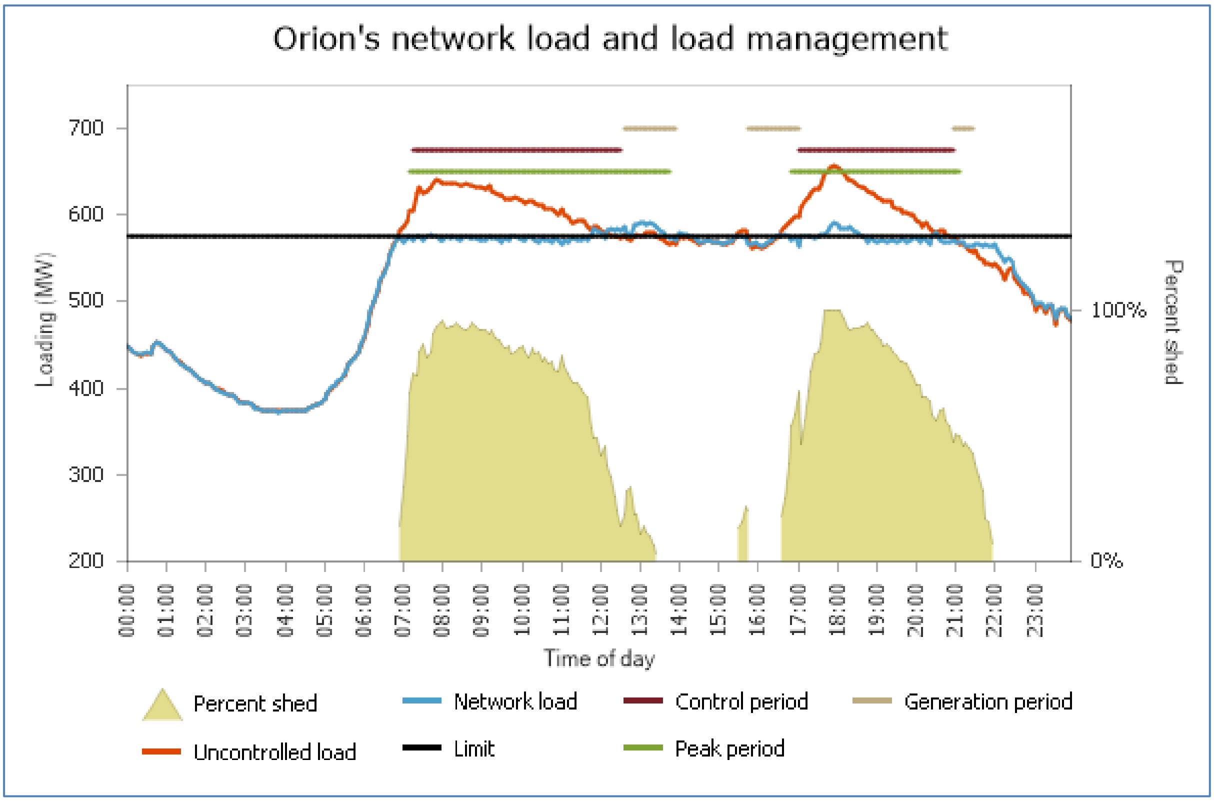
- the LV network is typically built by the developer, and is usually purchased from the developer by Orion (the developer does not have to sell the LV network to us – they could retain it or sell it to another party). The LV network will typically provide for a 15kVA connection for every ICP.

- Orion provides HV capacity to the connection point with the LV network. That capacity is based on the number of connections in the subdivision and generally uses an average after-diversity maximum demand of 5kVA per connection.

Most of the cost of the LV network is both sunk, and driven largely by construction costs rather than asset costs. So it would not be much cheaper to build less local capacity, but it would be very expensive to retrofit additional capacity if it was subsequently needed. There is thus a substantial option value in building robust LV network up front. All customers, over the life of the assets, benefit from this option value.

4.2 Peak demand and load management

Our current peak demand pricing is strongly linked to load management. Both are most important on the coldest days. On such days our load management makes the load virtually flat between 7AM and 9PM. The following graph for 8 August 2016 shows this.



By way of explanation:

- the black line is the network limit we seek to control to, the blue line is the actual load and the red line is our estimate of what the uncontrolled load would be,
- the yellow shaded areas show the percent of ripple channels shed across the day (note that only for relatively short periods are all channels shed at the same time), and
- the three sets of lines at the top show the durations of our general peak periods (green), major customer control periods (purple) and generation periods (beige).

Overall the objective is to maintain the demand on the coldest days as low as possible without failing to meet hot water heating service levels and given the combined effect of other demand response.

Peak load management incorporates both the centrally coordinated switching off and on of hot water cylinders, and the customer managed response to our peak pricing signals from, mostly, major customers.

As well as peak load management, we also manage the switching on and off of storage heating loads over the low–priced night period. About 15 years ago we extended our night period from the normal 8 hours beginning at 11pm – used by many other distributors – to a 10 hour period beginning at 9pm. The extended night period allows us to stagger the times that night loads are turned on to deal with the 11pm peak that had emerged following significant uptake of day/night pricing from the mid-1990s. This was a real world example of how TOU pricing can shift peaks, and how that can be managed.

We understand that some retailers view emerging technology as providing other options to control load, and that our management of load is an impediment to that. We think this should be a broader industry discussion (which is occurring) but whatever the outcome we need to ensure that the impact on the customers (and in particular what they pay) is front of mind.

4.3 Low fixed charge regulations

In part the structure of our current pricing – with no fixed charge for general connections – is a response to the regulatory constraints imposed by the low fixed charge (LFC) regulations. The Authority has recently suggested that variable charges under the regulations can perhaps be more widely interpreted than we have previously thought. This is an interesting development and, on the face of it, it provides the opportunity to use capacity and demand charges more widely.

A key development here is the ENA's request to the Authority's compliance team to provide opinions as to whether a number of possible capacity and demand approaches are 'variable'. We have recently received this and are in the process of reviewing it.

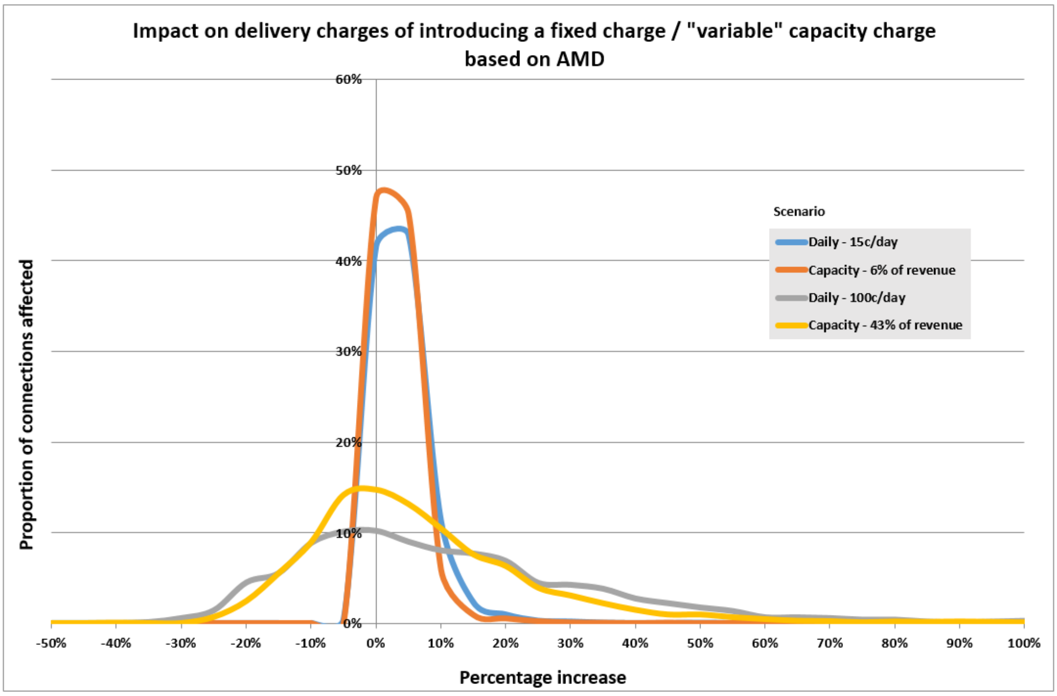
We also note the Minister of Energy's May 2017 indication that she has instructed MBIE to review the LFC regulations against the stated purpose, and this in the context of wider political party policy statements questioning the efficacy and fairness of the regulations. These developments also mean we might become much less constrained in our consideration of future pricing options.

However, and in the meantime taking the guidelines at face value, we have analysed the potential impacts of 'fixed' and 'capacity'[6] based pricing at various levels and have concluded the following:

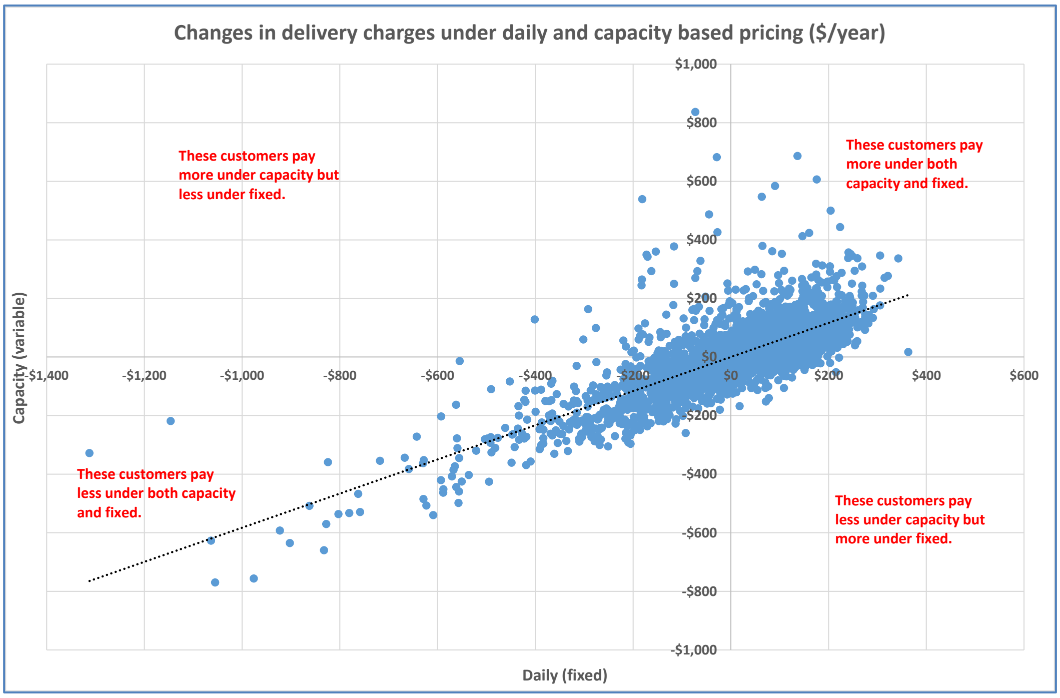
- Both forms of charging have very similar ranges of customer impacts where they raise similar amounts of revenue. (So in the graph below a 15 cents per day fixed charge is equivalent to capacity charges that raise 6% of total revenue for the category, while a $1.00 per day fixed charge is equivalent to capacity charges that raise 43% of revenue. The reason the median increase is greater than 0% for this sample is that the revenue neutrality

[6] For ease of analysis 'capacity' in this case is just the maximum anytime demand in the twelve month period. The source is interval data, provided by retailers, for around 2,200 residential customer ICPs.

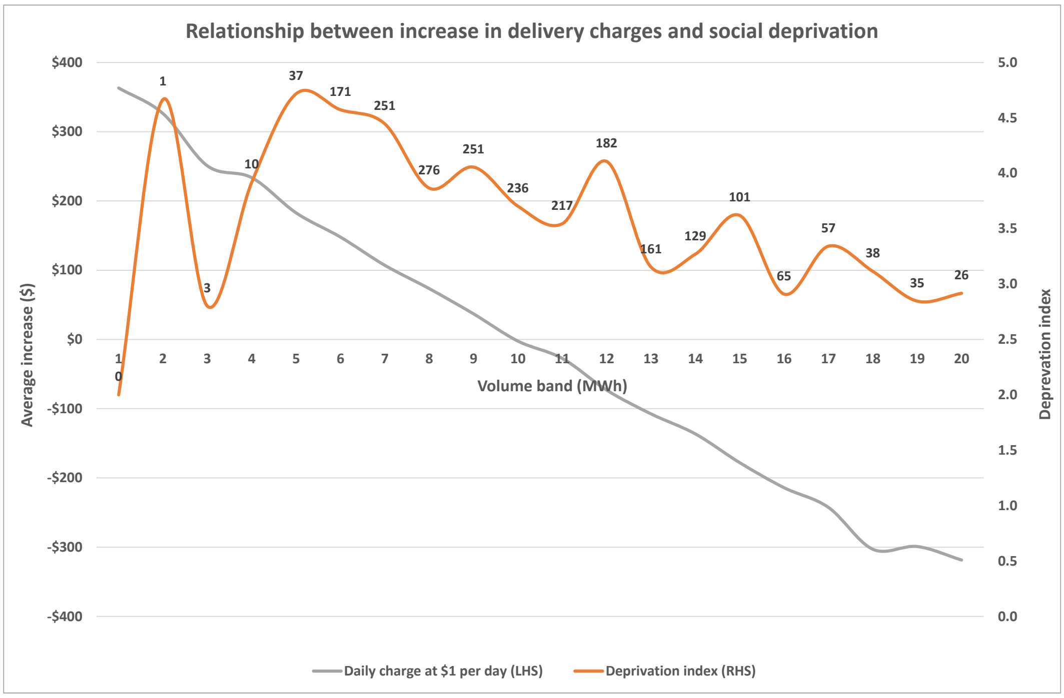
constraint is applied across the entire (very wide) general connection category, but residential customers, on average, have lower consumption than the category as a whole.)



- Customers are generally impacted in the same way under both ‘fixed’ and ‘capacity’ charging approaches, but there are some exceptions. The following graph shows this for a $1 per day fixed charge and equivalent capacity charge.



- Based on census data, those facing the largest adverse impacts under either approach tend to be the most 'deprived'[7] because, at least on average, those that use less energy tend to be more deprived. The following graph shows this for the $1 per day fixed charge case: the deprivation index series is downward sloping over most of its length. (The numbers above the orange line are the counts of customers in each volume band.)



It seems reasonable to assume that these sorts of impacts will occur with pretty much any material changes to our pricing, as there is significant variation across customers in the relationships of the various quantities: capacity, AMD, CMD and kWh.[8]

Perhaps more fundamentally, the LFC requirement that any variable charge, no matter the quantity in question, must reduce as the quantity reduces - and proportionally [9] - simply shifts the perverse incentives inherent in the regulations from one quantity to another. For example to avoid a maximum demand charge, a customer might invest in technology (say batteries) to reduce that demand, even though this does not normally result in a decrease in any costs of supply. This is not, conceptually, any different from the inefficiency that arises from a customer reducing delivery charges by installing PV. Not only will this create similar wealth transfer effects as, over time, prices increase to offset lower quantities, the investment in maximum demand management could be dynamically inefficient – it makes New Zealand as a whole worse off.

[7] 'Deprived' here is as measured by an amalgam, produced by the University of Otago, of census data on various social welfare attributes. 10 is most deprived, 1 is least deprived.

[8] The correlation coefficient for any pair of these quantities across the sample is typically around 0.50.

[9] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, regulation 16 (1) (a)

4.4 Transmission pricing

The Authority's ongoing transmission pricing methodology (TPM) review is likely to impact on any future changes we make to our pricing. It is too early to say what the final TPM will look like, but based on the proposals so far we see significant tension between the ideas that a significant proportion of transmission charges be in some sense unavoidable, while the LFC regulations require almost total variabilisation of charges.

Transpower is also proposing an 'operational' review of the TPM. While this is still being scoped, it seems less likely than the Authority's TPM review to have much impact our future pricing structure. However, it could well impact on price levels.

4.5 Form of regulation under Part 4 of the Commerce Act

The Commerce Commission has decided that non-exempt distributors will move from the current weighted-average price cap regulation to a revenue cap regulation from 1 April 2020. While the detail of this has not yet been developed, it appears likely that it will provide distributors with more flexibility in how they price, as there should be less risk associated with both price restructuring and particular forms of pricing.

4.6 Wider Electricity Authority work programme

The Authority has a number of relevant projects, including:

- Monitoring of distribution pricing reform via distributor road-maps and updates to them - ongoing
- Consultation on mass participation - in progress
- Review of the distribution pricing principles - later this year or early next year
- The default distribution agreement concept - further consultation coming soon
- Data and data exchange - consultation imminent
- Multiple trading relationships - consultation in September / October of this year

All of these have the potential to influence the timing and direction of our future work.

5. Options

5.1 What are the options?

A number of pricing options have emerged through industry work in this area and we have considered the attributes of these.

We are mindful that change in itself will involve costs and have an adverse outcome for some groups of customers, and we need to ensure that the benefits brought by any change will exceed these costs. At this stage we are keen to get views on the various possibilities, but we emphasise that no decisions have been made.

Within a mix of pricing components, a number of options have been proposed (see the ENA guidance paper) which we comment on (with the residential market in particular in mind) and these are discussed in the following table. We acknowledge that some of these options may be used in combination.

Price basis	**Comments**
Installed capacity (fuse based) pricing	At face value, helps address our problem of too much of our revenue being recovered from volume related charges. However, it reflects costs (sizing) of network capacity but only in relation to a very limited range of assets close to the premise, and is not cost reflective of upstream network. A customer's decision to reduce their fuse size will reduce the amount they pay but will not usually reduce any of our costs. Moreover, even if such charges are 'variable' under the LFC regulations, because such charges cannot, under the same regulations, be stepped or tiered, compliant capacity pricing would almost certainly over-incentivise capacity reduction. Compliant capacity pricing will therefore be neither cost-reflective nor service-based. Fusing is not currently available in the necessary incremental steps needed to provide meaningful choice of capacity. Outages occur when capacity is exceeded – current fuse devices are not customer-resettable. An outage would be required to check or change fuse size (current fuse sizing is not always recorded). Fuse size increases will require an assessment of safety within the premise (as an additional overhead). Is not compatible with the necessary reheating phases of current load management approaches, which would cause tripping in situations where network controlled reheating aligns with high load at the premise. Metering does not provide a good indication of appropriate fuse sizing (because fusing can trip over a much shorter duration than the half-hour average loading available from smart metering). Provides the opportunity for seasonal adjustment by the customer (which inappropriately reduces charges).
Network coincident peak pricing	Cost reflective of a wide range of network assets (we estimate that 40% of our network assets by value are sized to meet coincident peak load[10]). A customer reducing their contribution to coincident peak load will reduce the amount they pay and either reduce our costs associated with future upgrades, or make capacity available for other customers to use. Complex and requires some combination of seasonal, delayed charging or estimates and wash-ups that is not compatible, at customer level, with the residential or SME market.

[10] Note that this 40% is not comparable with the cost proportions shown in the earlier background section.

	Results are volatile at a customer level. For example, a normal weather related shift from evening peaks one year to morning peaks the next year can have a significant impact on an individual customer's charges in situations where that customer's own usage has not changed at all. Requires an assessment for new connections and for new customers at existing connections. **NB: This is closest to our current peak pricing.**
Customer peak pricing	Reflects cost of network that is close to the customer. Is not reflective of costs of the 'higher' network – eg customers reducing peaks in summer months will reduce the amount they pay but there is no reduction in network costs. Not compatible with the reheating aspect of current load management approaches. Peaks would likely occur during the necessary reheating phases of load management. Volatile – the charges are based on a measured result over a short period of time, and this can vary significantly from month to month (more than total monthly volumes vary). Most customers do not have any knowledge of their own peaks in real time, or what this might mean.
TOU pricing (peak, shoulder, off peak kWh pricing)	Actual peaks are typically short duration of 2 to 4 hours on a few cold days in winter, but can occur anytime over a relatively long winter season (extending to around 840 hours over winter). Spreading a higher peak volume price over this extended period (to ensure that the few peaks are captured) effectively dilutes the peak price to a low level. At this low price level all but the lowest cost (free) responses are viable. Is not compatible with current load management approaches as customers would ask that managed water heating load be off during the set peak price time - or achieve this themselves with a timer - simply shifting the peak to occur after the peak price time ends, and creating peaks on days where a diversified and uncontrolled load would not cause peaks.[11] This would also mean that this response was not available for higher value uses on the many days when its actual value for network purposes is near zero. We currently achieve a flat load from 7am to 9pm on the coldest (highest load) days, and any shoulder price during this period would simply shift load to that period, creating a peak. Promotes PV with higher day prices (including on sunny, low load winter days), enhancing the artificial reward that we are trying to address. The seasonal structure of TOU pricing might help with some of the limitations that otherwise arise with TOU pricing as might the relative strength of the price signals when more revenue is recovered via other components. **NB: This is closest to our current volume pricing.**
Dynamically signalled TOU pricing (a form of critical peak pricing)	Providing a similar level of cost reflectivity as network coincident peak pricing, dynamically signalling a set higher c/kWh volume price can provide a simpler implementation than network coincident peak c/kW/day demand pricing. Working in conjunction with a day/night pricing differential, a set additional volume price could be signalled when loading levels are high – all volumes in the signalled half hours would then attract the higher price. If set at a level similar to our current peak pricing, this additional volume price would be in the order of $1.50/kWh. (Our peak price is currently around $200/kW/year and is typically measured over 100 to 150 hours.) This allows the more widely understood volume pricing to be used on a dynamic basis. The problem is that the variation in duration of signalling a higher price at peak times creates charge/revenue volatility. This can be managed with a combination of:

[11] Important further context here is that most metering on the Orion network is 'inclusive' in the sense that the hot water heating or other controlled load is generally **not** separately metered. Some distributors have or are developing TOU pricing that only applies to the separately metered uncontrolled load.

	• Following the signalling of any high price period, an extra low price period could be signalled (probably during the night period or through the weekend). The magnitude and duration would be set to give back the additional revenue collected via the previously signalled higher price period (but not necessarily to the same customers). In this way, customers that elect to lower their load at peak times reduce their charge, and are also further rewarded for shifting their load to off peak times. • Any remaining revenue volatility could be accommodated under the revenue regulation that the Commerce Commission is considering, with any under or over recovery being carried forward to the following pricing year. The approach provides more appropriate (reduced) reward for PV because signalled peak times are much less likely to include the fine (sunny) weather periods that a fixed TOU pricing approach would capture. However, it is not compatible with current load management practices (because customers would ask that managed water heating load be off during the higher price period preventing the normal cycling and reheat periods used for peak control water heating). While simpler than peak demand pricing, the approach is also not aligned with current metering configurations, and, if it is to be 'passed-through', to reflect the approach in retail pricing structures would require the use of half hour metering (rather than using the currently configured 'registers') or the creation of new 'peak period' and 'reward period' registers. Otherwise rebundling would be required as now. **NB: This is a possible form of one of the "second wave" approaches identified in the ENA guidance paper.**
Fixed charges	Cost reflective of fixed costs including administration, operations and maintenance, and non-load dependent costs. Very simple and easy to understand. Promotes appropriate use of electricity intensive appliances (heating, electric vehicles) by allowing lower volume pricing that better reflects the energy costs. Aligned with the "all-you-can-eat" trend seen in retail offerings for other utilities, and in principle could be structured as a 'nominated capacity'. (The fixed charge would vary based on customer choice.) Allows volume prices to be reduced thereby: • reducing the extent to which, for example, PV owners transfer costs to non-PV owners • better aligning the load and export price (this avoids inefficient investment in technology that attempts to avoid export as it more accurately reflects the value of PV generation regardless of whether it is used on site or by neighbouring properties). But, currently limited by regulation to no more than 15c/day for primary places of residence using less than the regulatory threshold (9,000 kWh per year in Orion's case). We estimate that around 60% of residential customers use less than the threshold, and, if the effects of PV are included, this percentage would increase to around 75%. [12] Can be differentiated depending on the attributes of the connection. For example some distributors already have different (lower) fixed charges for connections with controlled supply. **NB: Orion's current fixed charge for general connections is zero.**
Rebates / credits for controllable load	Identifying suitable controllable load, like hot water cylinders, batteries or electric vehicles, and providing a specific credit or rebate where loads can be coordinated reflects the benefit that these loads can provide to the network. In other words, if a customer (via the retailer) offers Orion control of load, Orion pays the customer (via the retailer).

[12] Based on data to date, the installation of PV typically reduces metered consumption by around 2,000 kWh per year. Approximately the same amount is exported.

	The approach provides a significant level of flexibility and addresses many of the load management issues identified with capacity, peak and TOU pricing approaches, and is relatively simple to apply. This approach is similar to the lower fixed charge that some distributors (for example Alpine, Powerco) apply for properties with controlled water heating. The approach can be extended to other technologies that provide a network benefit, and a tiered approach could be used for different capacity devices, or different controllable access (eg a higher rebate for a greater degree of control, or even different locations). We already have in place rebates for irrigation customers who are willing for us to interrupt their supply in emergencies. However, funding the rebates is a cost in itself, and recovering this cost via other prices risks aggravating the non-cost reflective behaviour responses that are at issue. The approach also implies a need to ascertain and verify that suitable controllable load exists and is maintained. This requires an audit process, and a process to cancel rebates where conditions are not met. This can be particularly problematic for things like EVs, as they can be easily plugged in to charge at a non-controlled source, but technology may help address this. **NB: This approach is one not discussed in the ENA guidance.**

5.2 Comparing the options

We have considered how the options above, and several others, compare in terms of complexity and cost reflectivity. The comparison is quite subjective and is made primarily with residential customers in mind. In reality, a pricing structure would probably draw features from more than one option so this also needs to be considered when comparing the approaches. Notwithstanding the desirable attributes discussed in section 2 above, our two key criteria at this stage are that alternative approaches should:

1. Address the excessive variabilisation of our pricing via our volume prices, and
2. Provide a workable alternative to our current peak pricing that preserves or enhances customer load management response.

We are of the view that our current pricing, or at least the peak component, is cost-reflective, but also brings a level of complexity that is beyond the scope of implementation for residential connections.

We have noted from the responses to the recent consultation by the ENA that the most preferred form of pricing is 'static TOU' (static as in pre-defined times), yet our analysis so far indicates that some types of this, and in particular any form that tries to use a peak, shoulder and off peak structure, are incompatible with our current approach to load management as they are likely to simply shift the peak (and create peaks on days that would not otherwise have peaks). It is also difficult to structure TOU pricing so that it provides sufficient reward to those customers that do chose to allow parts of their load to be controlled. We have not yet found a structure of static TOU pricing that will, of itself, achieve the same stable and optimal load management outcome on the coldest days while also providing a material reward for customers who choose to participate in load management. We also consider that static TOU pricing, even when implemented with seasonally higher winter prices, has the potential to enhance the inappropriate reward for PV, as any defined peak times will inevitably capture sunny low-load days. A more 'dynamic' form of TOU pricing may offer a better solution.

Our emerging view is that:

- Any alternative pricing approach, if it is to be service-based and cost-reflective, requires a higher proportion of revenue that is less susceptible to quantity reductions: in other words, higher fixed charges, or at least capacity charges that do not vary proportionally with changes in capacity.
- For the remainder of the revenue requirement, two of the above approaches merit further investigation: dynamic TOU and the reward / credit for customers who are prepared to have their load managed by us. Of the two, dynamic TOU appears to be most similar to our current approach, while rewards / credits looks to involve considerably more business rules and audit requirements than we currently have.

Seen though the customer (residential and SME) lens, the credits look to be simpler, more transparent and more understandable while both supporting the valuable load management status quo, and potentially providing a basis for application to other technologies that provide network value.

Q2.What are your views on our preferred approaches for further investigation? Should we explore these approaches further? What other approaches should we explore, and why? Are there any other criteria that should be applied?

6. Proposals and feedback sought

6.1 Introduce a fixed charge for general connections

As an initial step in our pricing changes, we propose to introduce a 15c/day fixed charge for general connections (including all residential connections) from 1 April 2018. Other components of our pricing would reduce so that total revenue from the category remains unchanged.

We can see the following benefits from this change:

- It signals a direction of travel to a world that is more based on the cost of providing the bundle of services that connection to a distribution network provides.
- It enhances our system capability to apply fixed charges across broad categories of customers, ready for a more significant application of ICP based charging in future, should this occur (and we think it is highly likely).
- Is a useful transition to applying higher fixed and lower variable pricing for larger (particularly non-residential) customers in future.
- Allows us to (slightly) reduce the price components that contribute to the high retail volume pricing, particularly the daytime price, which customers are exposed to. This helps (again slightly) reduce the cross-subsidy available for certain technologies.
- It is consistent with the approach taken by a number of other distributors.
- It is likely to be consistent with any of the possible future options that we take.

Customer impacts of a 15 cents per day fixed charge

Because of the interaction with retailer pricing and the LFC regulations, there are three ways that the introduction of a 15 cents per day fixed charge would impact on customers:

1. Low user residential customers at primary place of residence - the low fixed charge regulations apply and retailers would need to absorb our 15 cents per day within the total allowable 30 cents per day.
2. Residential customers not at primary place of residence - often a holiday home, LFC regulations do not limit fixed charges, so retailers could increase fixed daily charges.
3. High user residential customers and business customers - again retailers could increases fixed daily charges. ("Business" here does not include irrigators or major customers as they have their own pricing categories).

Below is the estimated impact at retail level for various levels of consumption, assuming retailers pass our price changes on. The largest decreases are bigger than the largest increases (in absolute terms) because the most annual charges can increase is $55 excluding GST, being 365 days times 15 cents per day, for a customer that uses no energy, while the decreases are limited only by the level of consumption: the more you use the bigger the dollar decrease. (Note that these impacts are not directly comparable with those shown in the graph on page 9 above as those were delivery only, not retail, and the LFC effects did not apply.)

	Estimated impact of 15 cents per day fixed charge on delivery cost at retail level by type and consumption band*			
Type	Attribute	Lowest 10%	Middle 80%	Highest 10%
1	Number in band	15,200	121,600	15,200
	Annual kWh range	0 to 3,540	3,540 to 13,650	13,650 to 114,600
	$ per year change	+$0 to +$7	+$7 to -$6	-$6 to -$500
	% average change	+0.6%	+0.6%	-0.6%
2	Number in group	700	5,800	700
	Annual kWh range	0 to 340	340 to 15,600	15,600 to 92,100
	$ per year change	+$63 to +$61	+$61 to -$16	-$16 to -$400
	% average change	+23.5%	+4.4%	-0.8%
3	Number in group	2,000**	16,200	2,000
	Annual kWh range	0 to 330	330 to 81,900	81,900 to 1,720,000
	$ per year change	+$63 to +$61	+$61 to -$353	-$353 to -$9,000
	% average change	+23.5%	+2.4%	-2.0%

* Retail $ values include GST.

**Many of the 'small business' connections in group 3 are unmetered supplies such as small telecommunication equipment and bus shelters. These use very little energy.

Implementation of such a change involves - and is conditional on - some billing system changes for us, and we will also need some new business rules:

- It is our current intention to charge for all general connections with status 002[13] and based on the days an ICP is with a retailer in each month.
- Since we bill partially in advance we will estimate quantities based on the latest information available.
- We intend to wash up the quantities and charges according to our washup cycle for volume charges.

We presume the change will have very limited impact on retailer systems and processes as fixed charges are a very common component of delivery pricing – pretty much all distributors have them.

Q3. Please provide your views on our proposal to implement a 15 cents per connection per day fixed charge for all general connections. Do you agree with the impact analysis above?

[13] We may also need to consider the status reasons. We note that some status reasons for the de-energised status are inconsistent with the connection being physically de-energised.

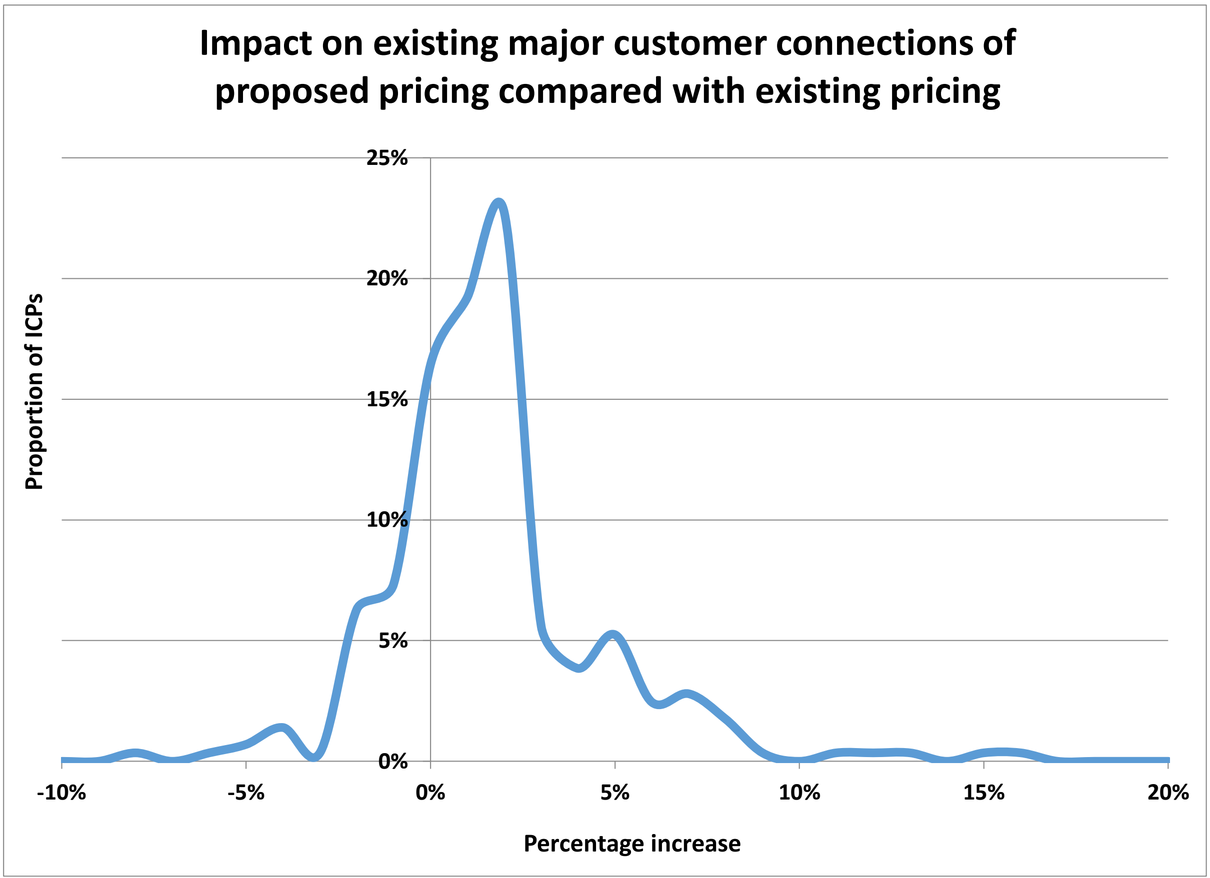
6.2 Some changes to major customer pricing

Over recent years we have been reviewing the classification of customers to our connection categories, and this has resulted in significant changes – both increases and decreases – in annual cost for some customers. A number of affected parties have questioned whether the cost changes associated with reclassification are reasonable. We have considered this feedback, and we agree that we need to make changes to address the very low level of charges in the major category that occurs when loading levels reduce below those intended for the category. In turn, this helps lessen the step-change in costs as customers move between the major and general categories. This change allows us to widen the range over which customers can elect either the general or major category. Together with the lower general volume pricing (associated with the introduction of the 15 c/day fixed charge) these changes materially reduce the step-change in cost at the category boundary.

The proposed changes to major customer pricing are:

- Reduce the bottom end of the band where the retailer or the customer may **elect** to be a major customer to loads regularly exceeding 150kVA (currently 250kVA),
- Introduce a 300kVA **minimum** for metered maximum demand (MMD) - in other words, the same approach as we take for nominated maximum demand (NMD), and
- Rebalance the charges within the category by increasing the fixed charge component from $1.89 per day to $10 per day, while decreasing the other price components, most likely the CPD price, accordingly.

The following graph shows how these changes would, in due course, impact on existing customers, on the basis that the same revenue is recovered from the group:



We note that there are a small number of customers more significantly affected, and for those with increases from these changes of more than about 6% we would individually consider a phased in approach by progressively applying the 300kVA minimum MMD over 2 or 3 years (and individually communicate this to the customers affected).

Further, where we have reviewed a connection's category in recent years, we propose to revisit those to see how our proposed changes would have changed the decision. With the wider band where a customer may elect their connection category, there may be situations where we can withdraw our notice to change category, and situations where a previous change can be reversed. Again, where we find a possible benefit for a customer in this group we will individually communicate with the customer highlighting the option to change.

Q4. Please provide you views on these proposed changes to major customer pricing.

6.3 Complexity of current arrangements

Our peak charging sits at the more-cost-reflective end of the scale and appears to already align with the direction in which the Electricity Authority is encouraging distributors to move. However, it brings with it a high level of complexity that is difficult to implement, particularly within residential markets, but also in SME markets. Customer issues aside, we often hear from retailers that they find our arrangements a challenge to comprehend and accommodate, and we interpret this as a call for a simpler approach.

Q5. Please provide your views on the trade-offs between the more cost reflective and service based pricing, and our perception that the industry and customers are seeking simpler and more standardised approaches.

6.4 Future direction

Above we set out our preferred approaches for further investigation:

- a higher proportion of revenue that is less susceptible to quantity reductions: in other words, higher fixed charges, or at least capacity charges that do not vary proportionally with changes in capacity,
- for the remainder of the revenue requirement, dynamic TOU pricing or rewards / credits for customers who are prepared to have their load managed by us.

We will need to have the regulatory limitations of the low fixed charge regulations addressed if we are to implement either of these approaches.

6.5 Rate of change

In terms of the more fundamental changes discussed in this paper, some retailers have expressed a view that changes should be made in one go, not progressively over a number of years. This minimises the cost of change, but results in significant cost changes and even rate shock for some customers that might otherwise be spread over a period of time. The Authority has indicated that changes should be smoothed in over a number of years, and we tend to agree with that approach, and our 15 cents per day proposal is an example of that, as is the phasing in of the proposed major customer changes.

Q6. Do you agree that further changes should be applied progressively?

7. Special topic – a spot market for distribution?

Our delivery pricing development has led us to form the view that any pricing arrangement that results in known-in-advance high or low prices at known times (be they pre-defined times or signalled times) is either unstable or can be gamed, or probably both.

This is at least in part because the prices tend to be binary, rather than reflecting actual real time conditions. Thus the prices tend to be too high or too low at any point in time.

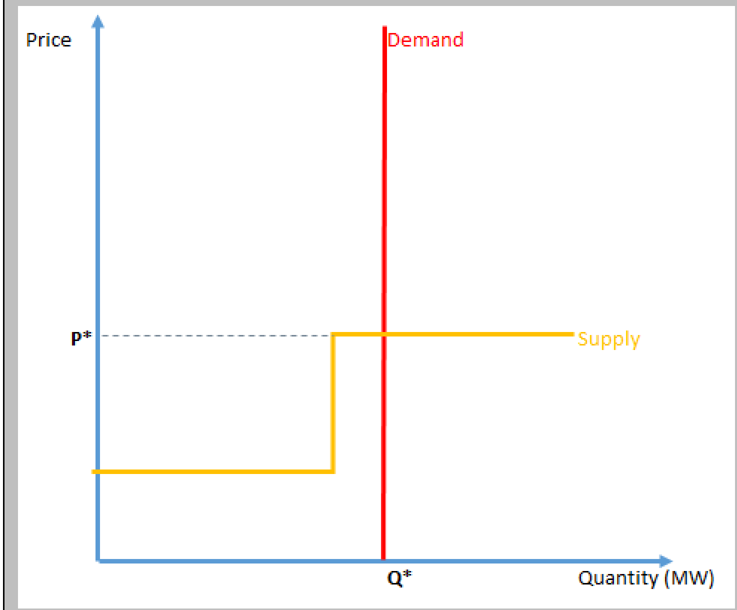
This raises the possibility that distribution pricing, or more specifically price levels, could be more dynamic, and perhaps be like the energy market. While there may be all sorts of barriers to actually doing this, it is worth thinking it through to see if there are any relevant ideas.

7.1 Energy market recap

The wholesale energy or spot market matches supply and demand at a few hundred 'nodes' that are connected by the grid. The grid features multiple pathways between points of injection and offtake, and depending on demand and supply conditions the power flows on the grid can vary considerably.

Pricing at each node reflects a combination of demand, supply, security and network constraints. The system operator dispatches available resources to minimise the cost of meeting demand subject to meeting security requirements.

The simplest static representation of this is typically as follows:



To explain:

- Generator offers are depicted as a (yellow) series of steps because there is typically a given price for a MW range, and this makes up the supply curve. (Note there are typically many more than two steps.)

- Actual demand (Q*) determines the clearing price (P*) based on where it intersects the supply curve. The highest 'cleared' offer sets the price for all generation and demand.[14]

Things get a little more complicated when supply and demand occur at different points on the grid.

So long as there are no constraints on the grid, differences between the price paid to generators and the price paid by demand reflect marginal grid losses, which are modelled as varying in a stepwise fashion according to the demand on each circuit.

However, where there are constraints on the grid – one or more circuits cannot support all of the demand at a distant point - the relationship between offer and clearing prices at various nodes becomes more complicated. The price outcome is sometimes referred to as 'price separation'.

Whether or not there is price separation, the price differences between nodes are sometimes referred to as representing the short-run marginal cost (SRMC) of transmission.

There is an even more extreme outcome where there is insufficient generation to meet expected demand, either locally or overall. In these 'scarcity' situations there are a variety of administrative processes and price outcomes set out in the Code.

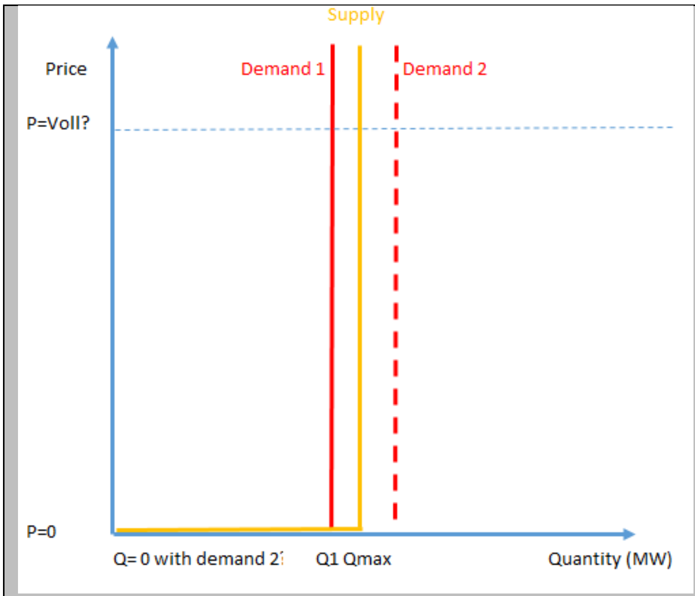
7.2 Application to distribution pricing

If we think of 'nodes' as ICPs, there are many more 'nodes' on a distribution network, even a very small one, than there are on the grid. Nevertheless at a high level, conceptually, a distribution network is very similar: it can be depicted as an interconnected set of nodes with the interconnections varying in number, length, voltage and capacity as we move from the points of grid connection (7 in Orion's case) down though our 53 zone substations to around 11,000 distribution substations, innumerable boundary boxes and finally 200,000 or so supply fuses.[15]

Load at any node will vary, and the path over which it is supplied can also vary. Various parts of the network, at various times, will be constrained. In principle all of these variations and their effects could be modelled along the lines of the spot market, and the resulting prices would represent the SRMC of distribution.

But going back to first principles it is useful to think about the first diagram above, and how this might look for the distribution service in a very simple world.[16]

[14] It is acknowledged that the price setting process provides for demand side response to be factored in, but that is ignored here in the interests of simplicity. Consideration of the demand side returns below.
[15] Beyond the supply fuse, the wiring and appliances within a connection can be thought of as further extensions of the overall system with multiple circuits at multiple capacities and voltages connecting multiple appliances.
[16] And much more simple than the real world. Not only might constraints occur at many points in the system, but decisions made at particular points in time change the value of consumption later. For example the value of hot water heating goes from being near zero when the water is hot to a higher value as the amount of stored hot water decreases due to use and thermal losses.



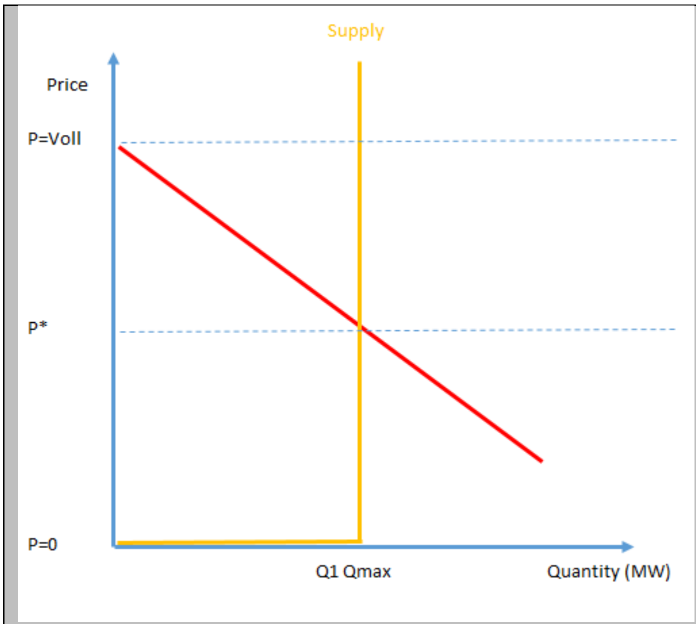
The first thing to note is that there is no supply curve as such. The network has a certain capacity, and in the short term this cannot be changed. Up to this capacity, the SRMC-based price is effectively zero as the available capacity can be 'produced' at zero marginal cost. Once capacity is exceeded it is difficult to say what an appropriate SRMC of supply is, but VoLL would seem the best candidate.[17]

However, this outcome assumes that demand is itself a given. If we relax that requirement things get a bit more interesting.

At any point in time aggregate demand for electricity is made up of many different end uses. Each use will have a particular value to customers, and these values will vary. In principle customers will be prepared to forgo any particular use if the price is greater than the value they place on it. The upper bound on this is VoLL, but there are likely a number of uses where the impact of not using electricity right now would be much less than VoLL. One example is storage heating where there is a delay between when the electricity is used, and when the stored heat is used. The most common example is hot water cylinders.

Stacking all of these uses and associated values would create a more traditional downward sloping demand curve as depicted below, and would in principle enable the setting of a market clearing price (P*) for any given supply (capacity).   However, whatever this price is, it is not based on the distributor's costs. If it reflects any cost at all, it is the opportunity cost to the customer of not using the last unit of electricity.

[17] Capacity being exceeded implies the physical tripping of a piece of protection equipment, which reduces measured demand but at the cost of the value of the unserved energy.



In a sense this can be thought of as a short term secondary market in capacity. Suppose (and again this is very simplified) there is 500MW of capacity available, and in the absence of any price signal demand would be greater than the available capacity at 600MW. Customers could in principle trade based on willingness to turn loads off so that capacity was not exceeded. The price required to induce a customer to turn the (lowest) value 501st MW off would set the market price.

The world where loads could be ranked and priced in this way is very different to the current world, but it is conceivable that, in the future, with a combination of software, home energy management systems, smart appliances and the internet of things that such an outcome could be achieved.

Our current peak pricing approximates this outcome, but only very roughly, since it is both a known on-off price, and because it is a price based on estimates of our long run costs of providing new network. The market clearing price described above, being short term and demand driven could be more or less than our long run price.

The system works at the moment because the key element of demand response is managed by us, so the instability that would likely arise from all demand response occurring at the same time is avoided. With potentially greater use of alternative technologies managing demand response, our ability to continue to do this may diminish.

Our current load management can therefore be seen as a service that we provide that approximates, via institutional arrangements, an outcome that might be delivered in a dynamically priced market, but with much lower transactions costs. We effectively build firm capacity to support highest value loads at highest (coincident) demand times, while maximising the extent to which lower value loads can be managed so that, in aggregate, load remains within that firm capacity. This arrangement manifests itself via the network planning process much more than it does via price setting. It allows us to better align the long run costs that underpin our and customers' investments with the short run balancing of supply and demand.

Q7. Please provide your views on a whether the future is likely to encompass a dynamically set or 'spot' price for the distribution service? If you agree, which of the approaches discussed above, and in particular which of our two currently preferred approaches, would be a useful intermediate step?

8. What happens next?

We want to receive your feedback on this document by 5pm on Friday 29 September. This can be emailed to pricing@oriongroup.co.nz.

We are happy to discuss this paper with you prior to your providing feedback: please email or call: bruce.rogers@oriongroup.co.nz, 03 363 9870 or 027 6789 744.

To the extent the feedback relates to our specific proposals for changes on 1 April 2018 – a 15 cents per day fixed charge for general connections and changes to major customer pricing - we will respond with decisions by the end of November 2017 at the latest.

In terms of our longer term pricing work programme we expect to provide some responses around the time we formally advise retailers of our 1 April 2018 price changes - in late January or early February 2018. However, other feedback may be responded to or reflected subsequent to that. We note that we indicated in our February 2017 pricing methodology that significant changes to our pricing, if any, are unlikely to occur before 1 April 2020. There will of course be additional consultation before we make any further changes.

9. List of consultation questions

All of the questions in the paper above are included in the following table for convenience.

Q1. Have we captured the problems with peak pricing? How should we weight these against the alignment of peak pricing with other pricing principles?
Q2.What are your views on our preferred approaches for further investigation? Should we explore these approaches further? What other approaches should we explore, and why? Are there any other criteria that should be applied?
Q3. Please provide your views on our proposal to implement a 15 cents per connection per day fixed charge for all general connections. Do you agree with the impact analysis above?
Q4. Please provide you views on these proposed changes to major customer pricing.
Q5. Please provide your views on the trade-offs between the more cost reflective and service based pricing, and our perception that the industry and customers are seeking simpler and more standardised approaches.
Q6. Do you agree that further changes should be applied progressively?
Q7. Please provide your views on a whether the future is likely to encompass a dynamically set or ‘spot’ price for the distribution service? If you agree, which of the approaches discussed above, and in particular which of our two preferred approaches would be a useful intermediate step?