Submitter	Bruce Palmer Private individual tuisoftware@gmail.com

I approach this not as a representative of a market participant, but as an IT person who will be tasked with making system changes to meet whatever it is that is the outcome of this process.

I ran a project in early 2019 that investigated the entire gamut of distribution charges, constraint charges, ToU pricing, capital contributions and target revenue apportionment. There were a number of findings from that project that may be relevant to this consolation; the main being:

- The standard approach for ToU billing (peak, shoulder and off-peak) was not sufficiently granular to be useful for sending price signals;
- The volume price for a period *could* be derived by formula using parameters of period load, acceptable maximum load and LRMC making it possible to have a significantly larger number of price points than under a three-timeband system;
- Capital contributions could be expressed in terms of ADMD, anticipated share of ADMD, acceptable maximum load and LRMC, thereby linking them into a consistent structure; and
- LRMC needed to be priced as if the next five years of planned development (as disclosed in the Asset Management Plan) had happened or it was understated by not including upcoming “really lumpy” assets.

The project findings outlined a pricing approach that was somewhat different to where the distributor was at. There were a number of winners and losers, with the losers concentrated around the smaller end of residential consumption. Given that the business environment involved a pre-determined target revenue, all of the most disadvantaged consumers had a vote, and the entire process would have the effect of causing significant disruption for not a cent more profit, the initiative was kicked to touch.

I cannot state how they, or any other distributor, are thinking now, but I am aware that, if investment dollars need to be spent, there would often be preference to spend these on the network asset (resilience, SAIDI/SAIFI, n-1 redundancy, “keeping the lights on”) as opposed to increasing the number of administrative staff and the complexity of IT systems.

I start this submission by recording thoughts on various aspects of the paper as I read through; often in places where specific consultation questions were not necessarily asked, or even applicable.

Climate resilience

My first observation relates to overall construction styles.

Electricity networks are built to the larger of two design considerations:

- The ability to convey the peak load without sustaining damage, generally including (n-1) fault tolerance for larger consumers; and
- The ability to withstand local climatic conditions

If a circuit is exposed to 150km/h crosswinds, or can receive 20cm of snow overnight, or has 200m-plus gullies to span, or similar, then it needs to be constructed to an engineering rather than a conveyance standard, and use components of sufficient structural strength to handle the conditions. Such construction is likely to be capable of conveying vastly in excess of the electrical loads it is asked to carry, with peak demand congestion never likely to be an issue.

The percentage of networks built to an engineering rather than conveyance standard is likely to increase as a response to climate change, worse weather and events such as Gabrielle. No amount of modern price plans, fine tuning of time of use charges or price signals will convince network engineers, mindful of SAIDI and SAIFI constraints, not to build to an engineering standard where required.

The portion of network asset to which the matters in this consultation refer; those built to a capacity standard, suffering congestion and where the timing of the resulting upgrade can be influenced by consumer behaviour, could be expected to decline.

Introduction "*This paper discusses the regulatory settings for distribution pricing and how to ensure they support the shift to a low emissions future at the least cost to consumers.*"

There is no doubt that increasing the emphasis on electricity as the primary energy source available for industry, households, transportation etc. will encounter capacity constraints therefore place investment demands on infrastructure.

This is not the same as "a low emissions future".

The result is "low emissions" only if the new generation does not involve carbon. For example, electrifying large industrial plants at Waiuku and Te Rapa does nothing for a low emissions future if all it does is move the place at which Indonesian coal is burnt by 25 km.

The paper has no view on decarbonised generation or what is needed in the way of price signals to encourage it. The paper does however contain the observation that off-peak DG is presently subsidised by poor pricing policies (section 2.10(c)). The consequence of fixing the pricing policies and removing the subsidy could have the long-run effect of suppressing those DG schemes presently of marginal economic benefit, which are relying on the subsidy to pass an investment hurdle. Sending a price signal to not initiate such schemes would appear to be "efficient" in terms of the Authority's world view as it prevents investment in a scheme that requires a subsidy to be profitable, but it is not helpful for decarbonising.

Introduction "*The Authority is concerned that progress toward more cost reflective pricing is not occurring as consistently or as rapidly as required*"

The transition from horses to motor vehicles was relatively rapid, as was the transition from wringers to automatic washing machines. Early adopters saw value for money and a superior product/service; these provided the early cashflow and led to the economies of scale that reduced the price and allowed the entire industry to transition.

Maybe the move to cost reflective pricing is stalling because the early adopters are not seeing the benefits, or are receiving pushback from customers and stakeholders, so the unstoppable inertia is yet to get started.

Or maybe it just does not work as advertised.

One of the more constrained parts of the country is in the Waitaki Valley where the associated substations for two distributors are around or beyond (n-1) capacity limits in the middle of summer i.e. if a component failed, the remaining capacity would not be able to handle the demand.

The permanent solution is a new grid exit point; Transpower has estimated $35M.

Discussions for a special protection scheme i.e. paying large consumers to disconnect at peak times, are already in progress. This will not solve the problem, but is economic because the subsidies to those few large users should cost less than the benefit of kicking the problem to touch for a few years; in particular, to buy enough time to do the work.

This resolution had not required peak load price signals. Such signals vanish into retailer overheads and have no visibility to consumers, particularly in a summer-peaking network. Here, the distribution price signal would be counter-cyclical to the energy charge; the retailer would be price-signalled that it is a good time of year to use energy but a bad time to distribute it.

Introduction "*there is wide variation in approaches to assessing whether cost allocation is subsidy-free"*

There is one area of subsidy I do not recall being discussed at any stage.

A number of otherwise uneconomic circuits that should never have been built, were constructed with assistance from the Rural Electricity Reticulation Council (RERC). A number of these are at end of life, but the distributors are stuck with the connections under the Continuity of Supply conditions of Section 105 of the Electricity Industry Act. There are only four options:

i) Island the site, but retain responsibility. Any landholder can veto this option.
ii) Sell the ICPs to the neighbouring distributor, who may have an easier path for access. This does not discharge obligations under 105(4) leaving the first distributor responsible for any failings of the second.
iii) Replace the circuits and charge the consumers the true cost. This is often a massive increase over what has been paid previously. Where the landholders include private residences, this charging is prevented under the LFC regulations without special dispensation first being granted.
iv) Replace the circuit and subsidise the pricing

I expect the Authority would take the view that if the consumer could not pay the true cost of their supply, they should not be supplied. Unfortunately the Continuity of Supply legislation does not concur. Islanding is not always possible; not everyone in remote areas is positioned with reliable sunlight, water or wind. Installing diesel is an option, but that is not in alignment with the decarbonisation objective.

Some subsidies are unavoidable, and can even preferable to other options (such as diesel). Unless the Continuity of Supply provisions are to be repealed, or RERC reinstated, recognition of the issue would be useful, in the same way that "growth levy" is incorporated into Section 2.25.

Introduction "*The Authority seeks to balance several factors while considering these current concerns"*

There is one set of balancing not referenced within the consultation.

"Efficiency" within this paper is presented in terms of location and time specific cost-reflective pricing. This ensures that the correct signal, and only the correct signal, is passed from distributor to retailer for when the latter is considering intervention or technology investment decisions that will affect how their customers consume electricity.

The most accurate signal would involve half-hourly pricing (i.e. varies per trading period) with the price directly correlating with congestion at the location and reflecting the cost and planned timing of the next capacity upgrade.

With smart meter HHR available per ICP, congestion could be assessed per trading period, at the phase level, per transformer. It does not get much more location or time specific than this. If volume pricing was linked with congestion data at this level, it would send a precisely targeted location and time specific signal to the retailer. The retailer would know the most congested ICPs, and the trading periods where the transformer had the largest trouble, so could micro-manage their interventions to the specific locations and times of network pain, where the price to them would be the highest and avoidance of that price give the most benefit. It is difficult to imagine a price signal more precise, therefore more efficient, than this.

However, there would be a need to not become distracted by the volume of data; say 5000 transformers averaging 2.7 phases, for 1460 trading periods for the current month, (plus the three historic months being washed up). Is 80 million price points per billing cycle too much, to send precisely targeted location and time specific signals? There is a good chance that retailers and distributors would both be happy with less accurate targeting.

The Authority needs to balance the various types of efficiency that are present; in particular the efficiency of the price signal versus the efficiency of the back-office system that is needed to produce it.

There are other types of efficiency needed in the industry, such as how build more resilient network components at less cost (construction efficiency), how to make components last longer in the field (longevity efficiency) and how to reduce line losses (engineering efficiency). Distributors are undertaking this sort of research without needing direction (or Code changes to enforce compliance). This is possibly because they see direct benefit to them from the work, in a way the location and time-dependent peak load price signals does not.

4.8 "*vehicle-to-grid injection could further relieve network investment pressures*"

This is true only if, once drained into the grid, the owner has sufficient time to recharge their car for when they want to use it. Compulsory acquisition of the owner's energy ignores the fact that deep-cycling the batteries each night halves their life. Battery replacement is not cheap and can exceed the scrap value of the vehicle.

Finally, in a system powered by a high portion of new technology renewables, you can get into a situation where the sun isn't shining, the wind isn't blowing and the vehicle fleet is flat.

EV owners may be less enthusiastic about the technology than the Authority.

4.9 “*a network planning approach that no longer adds capacity well ahead of demand*”

This is the kind of planning that gave us the Auckland Harbour Bridge. Demand was for two lanes each direction, within two months it was obvious another two lanes each way would be necessary. It is far more economic to build it properly in the first place, to a limit. It does not make sense to build taking 40 years projected growth into consideration as for at least 35 years, consumers would be paying for capacity not needed. However, building to present demand and having to come along in two years time to replace all the pole-tops and restring with heavier conductor is likely to be more expensive.

This paper could have considered the appropriate amount of growth to allow for when planning capital projects, this being another aspect of price setting and right-sizing the distribution network.

4.21(b) “*there is wide variation in the implied LRMC between distributors*”

Distribution networks are built to the greater of two design requirements

(i) The ability to carry the peak load to be placed upon it, plus a margin for error and growth;

(ii) The strength to withstand local climate conditions e.g. 150kph cross winds or 20cm of snow dumped on it overnight.

LRMC relates to network construction standards, as well as the percentage of construction where engineering rather than conveyance factors are primary. It also relates to proximity to the main grid backbone, and whether work requited on Transpower assets is charged to the distributor or socialised. I am not in the slightest bit surprised there is a difference in LRMC between distributors.

7.7(c) “*process electrification can introduce large step changes in demand with opportunities to optimise cost vs. reliability*”.

Please do not equivalence reliability with availability. Customers understand reduced availability, such as water heating rippled off during evenings or irrigation guaranteed for only 10 hours during a 16 hour period.

“Reliability” relates to the concepts of unplanned outage, SAIDI/SAIFI, the lights not working when they are supposed to be on etc.

There are certainly opportunities to trade off cost versus availability. Trading cost versus reliability is more the sort of thing you find in developing nations.

Below, please find my comments to a number of the questions asked in the consultation paper. As stated, I do not speak for any particular distributor and my views are my own. It is just that I have “been here” before and may have something to say that someone sees value in.

Kind regards

Bruce Palmer

Rodney.

p.s. I ran out of time doing the proof easing, I apologise in advance for typos and spelling mistakes, and there may be text content that would have been reconsidered and deleted had the opportunity been available.

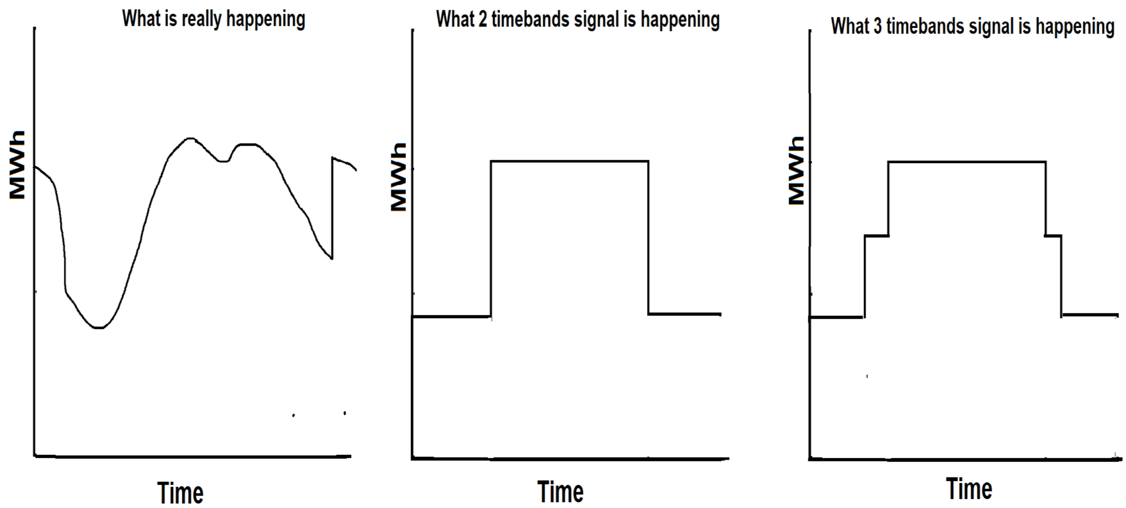
Questions
Q1. Are there other options that you think the Authority should consider? *Continuation, control or call in?* There is a 4th, "hands off" which would assume "the market knows best". If stakeholders found value from using price to alter customer load profiles and time of use, thereby reducing the capital demands for investment, then it would naturally become part of the tool set. Distributors have traditionally found high acceptance for load shifting in the form of ripple control, particularly because it is a set-and-forget option for the consumer and does not cause them much disruption. When ripple control is not sufficient, distributors enter into short-term arrangements with key users to disconnect at times of peak demand, while undertaking an upgrade. This approach is not "efficient" from an investment view, therefore a principle not supported by the Authority's empowerment legislation. Despite this, consumers have voted with their feet many times and shown an inefficient process producing a simple bill is preferred over complexity. But since when has any of the industry restructuring and modernisation been about what the consumers say they want? Consumers lack of engagement can be shown by the number of users who have never visited PowerSwitch, or are still with the incumbent retailer, or couldn't even do the once per year check to get the LFC/standard plan decision right. I am yet to see a Regulator who would voluntarily avoid an option to regulate, so it will be one of the suggested three. It may be the only way to break through consumer inertia.
Q2. Do you have any comments on the options outlined? The "Continuation" strategy is not achieving the results the Authority desires, quickly enough. Regulation always has the risk of being too heavy handed, making the Authority liable should there be unexpected effects, and running the risk of exceeding the social license the industry, its stakeholders and the politicians are presently allowing it. "Call in" allows the Authority to pick off distributors who happen to fall foul of its world view, and can lead to an East Germany or North Korea approach towards people who are not following instructions with the enthusiasm they have been told to show. The main reason adoption of the Authority's view is not progressing as fast as it would desire is that not enough stakeholders are seeing a compelling argument, sufficient to outweigh the other influences on their business. If they did, it would already be happening and "hand off" would be an acceptable approach. Which of the three options is best depends on how much public and industry support, and political capital, the Authority is prepared to burn to get to where it wants to get to, and how quickly it wants to get there. That is not my call.
Q3A. Do you agree that a combination of TOU tariffs and load control (appliance) tariffs would be useful for the smart management of peak demand? *Q3B. Do you consider that TOU pricing could have unintended consequences for congestion on the LV network?*

Q3C.Do you consider that use of shoulder pricing as part of the TOU price structure could be an effective way to mitigate this risk? What other ways could be effective?

Load control is useful, particularly if it is "set and forget" for the consumer i.e. agree to it and it just happens. The main problem is there are competing interests if there are competing providers; the distributor attempting to shave the top off peak load, and the retailer attempting to shave the top off peak energy prices. It may be necessary to state that the same facility cannot be controlled by both. Otherwise, if the facility is not working, or if it has been "off" for too long, then who does the fault lie with?

I spent a lot of time looking at ToU in early 2019. Here is a summary of what was found. ToU tariffs (and I note the word "tariff" is back in vogue after being discouraged for a few years) range from useful to useless.

They can be useful if the square wave daily profile they signal matches reality. But they fail to signal short dips during a timeband e.g. The network is not running at peak for all 12 hours of daytime. ToU timebands also put a large step change immediately adjacent to the band with the largest price; the signal being to move load to immediately each side[1]. This edge effect could be reduced by a shoulder period, but the resulting square curve must be mostly in alignment with the actual curve, or false signals will be given.



Examination of exactly this concept using whole of year data for a distributor for 2018 showed that for most times of the year the square curves were at best gross approximations and did not correctly signal where the load dips actually were. For example, 11pm to 7am was treated as flat-lined low volume, where an actual curve is shown above left. The distributor wouldn't have wanted EVs on the network until the hot water was out of the way; say 1am.

Optimum timebands were derived using best-fit analysis matching the square curve with the actual profile; this produced four different timeband settings across the year. Shoulder was sometimes a best match for 6am and 630am trading periods, at other times 630am to 8am. One GXP was an outlier and had a different set of timebands that were optimal for it; again these changed seasonally. The technique was applied to one GXP for another distributor, and its best-fit square curve was different again.

[1] While undertaking the load analysis. I observed a 20 consecutive working day period when daily peak demand at one location was just after 11pm. It was caused by ripple control, and users who were shifting load until the "night" period had started. The distributor was doing it to themselves.

If each distributor had their own optimal timeband structure, the impact on clerical efficiency for the retailers would be horrendous. There is no way that retailers, the public, EIEP12 or the published price schedule would have understood any of this. However, adopting a common set of timebands therefore square curves across the industry is no better than the dreaded profiling that this consultation has said elsewhere must stop where better data is available.

The conclusions from the project were:

- ToU splitting the day up into 3 parts is only a gross approximation of reality, prone to giving false signals. The one set of timebands cannot be optimal for all of weekdays, weekends and seasonally.

- ToU has to be more granular than 3 lumps with the middle one 12 hours or so in length, if it is to send correct signals e.g. we would need 12, 24 or even 48 prices per day; each related to congestion for its location, timeband and day. At least, this approach gets rid of the “shoulder” problem. This effectively meant that the modelling needed HHR actuals, which were not available other than at GXP level at the time. There was also no way to express this structure in an EIEP12 file, and considerable resistance from retailers could be expected. The resulting price modelling was scrapped and never presented to the Board.

Is ToU charging useful? As envisaged by the Authority, all it does is tell users that somewhere within a possible 14 or 16 hour period, the network is likely to be at its busiest for that day. If prices change seasonally, we are also told whether that peak is in a low month or high month for the year. I think this is all something we already know.

I agree that if volume is going to be billed, and the volume price varies across the day, then basing on meter readings where reliable and accurate is better than profiling a UN-24 meter. The Fair Trading Act demands as much.

Q4. Do you agree with the assessment of the current situation and context for peak period pricing signals? What if any other significant factors should the Authority be considering?

4.19(a) Has the Authority thought about the implication of what it is asking here? The claim is that each kWh is intelligent, and knows the consumer group that will consume it, therefore the cost profile it attracts as it goes though the network. Or that the a transformer running 15% over peak knows not to burn out because all of the volume is going to a load group that traditionally does not use a lot of volume at peak times.

The rest of this consultation asserts that pricing should be cost reflective. Each kWh sent through the network to adjacent ICPs on the same transformer and phase costs the network exactly the same, regardless of whether it is used by Great Aunt Mary to bake a batch of scones, or the school next door to photocopy 400 flyers. The more kWh you put through the network at peak times, the more you have caused cost.

I am however aware of extensive modelling of the likely impact of consumers of different load groups on peak demand i.e. how much of the spare capacity will be sequestered by this particular connection, so no longer spare, and this being the main consideration for the capital contribution for new connections i.e. the capital contribution is (mostly) based around the LRMC needed to restore the spare ADMD capacity that just got sequestered to supply this new ICP at peak.

Regarding Concept’s model, unless intelligence is assigned to each kWh, there is no way that kWh could cost the distributor a different amount to an adjacent kWh distributed at the same time. The place for considering the load profile is at the time of connection; how much spare capacity is going to be sequestered by the new connection. Add this to the cost of dedicated assets needed (e.g. some network service line, some fusing, maybe a transformer, maybe some switch gear) a charge for the paperwork and that gives you the Capital Contribution. The new ICP only adds to its share of ADMD and sequesters the matching part of spare capacity once, so it is charged only once.

For the concept of peak pricing signals, refer to comments earlier regarding ToU. If the ToU pricing was sufficiently granular, then peak demand pricing would already be present, it is just a matter of relating the ToU price to the amount of spare capacity (or the LRMC needed to be spent to restore spare capacity to the minimum levels of (n-1) resilience plus a safety margin. The modelling was done – in early 2019 – but the industry lacked the technology, capability and willingness to provide the data needed to do it.

Q5. Do you agree with the problem statement for peak period pricing signals?

To send a peak demand price signal you need to know the time of peak demand, and each ICP's share of that peak. In the absence of a full set od HHR data, the time of peak demand can be obtained from the Reconciliation Manager (process GR-040) or SCADA logging; it is needed to annual disclosures so is something everyone should have. Knowing everyone's share of it is something completely different, and requires HHR data. Refer to previous comments on ToU, the granularity of the timebands, and pricing each based on what is needed to restore minimum acceptable spare capacity at that time.

I accept that for most periods in most locations, volume would be priced at as (n-1) plus safety margin would not be under threat.

Q6. Do you have any comments on the Authority's preferred pricing for peak periods?

4.29(a) Fine

4.29(b) Fine, as long as retailers pass the HHR data to distributors either per trading period or timebanded into those bands required to match the distributor price schedules. The EIEP3 protocol exists or HHR data; the EIEP1 protocol may require revision in the area of register content codes if the timebands are as granular as modelling shows is needed to avoid giving false signals, and the shoulder effect

4.29(c) Yes, and absolutely no way. Agree prices should be linked to something. However, each kWh does not have intelligence and does not know how it will be used. I do not understand why the Authority is fixated with moving away from charging each kWh what it costs. The place to factor in load groups is in terms of the spare capacity the network no longer has, on circuits that are constrained, and at the time of Capital Contribution.

4.29(d) Yes, if a separate metered value can be given, then the principle of using actual HHR readings as the basis of time aggregation requires this.

4.29(e) Obviously, because each kWh distributed at the same time costs the same.

4.29(f) Only if the Reconciliation Manager is discontinued and all reference to reconciliation removed from the Code.

The purpose of the Reconciliation Manager is to receive submissions from generators, retailers and Transpower, and balance each reconciliation area within the country so that inflows and outflows are matched.

Reconciliation is required because the submissions never match without clerical intervention; retailers get the number of ICP-Days wrong, or they include ICPs that aren't theirs, or exclude ICPs that are, or cut off volume readings on the 22nd of the month an estimate the balance, or fail to read meters, or read meters twice etc. If the differences were miniscule, the industry would not incur the overhead of Reconciliation.

But it does.

Why?

Because the raw data from participants is not good enough to settle on. The reconciled data is considered gospel and is the basis for industry settlement. Everyone accepts this. I do not recall a single complaint or breach notice issued by a participant against the Reconciliation Manager.

Under the EIEP1 “RM” methodology, the kWh totals provided by each trader to the Reconciliation Manager must match those provided to the distributor. If the totals are that dodgy that the entire reconciliation process is needed, then why should retailers, generators and Transpower be allowed to settle using cleansed, balanced, reconciled data but distributors be forced to deal with the dodgy stuff?

This is the principle behind GXP billing:

i) Where HHR data is available (EIEP3 and those smart meters that submit), use it
ii) Where NHH data is provided, already packaged into the timebands needed, then use it unless the Reconciliation Manager has already overruled the packaging
iii) Everyone else, profile per HHR using a residual profile approach to match the profile provided by the Reconciliation Manager for that period, trader and GXP
iv) The available data from (i) and (ii) has to be grossed up by adding back line losses, or the GXP residual profile cannot be referenced as it is on a loss-included basis.

To put it bluntly, if Distributor A provides a list of ICPs and says they used 14,337kW during a particular trading period, and the Reconciliation Manager says, “sorry, I beg to differ, it is actually 19,412kWh” and everyone is happy with the larger value for settlement, then that is what is going to be billed by the retailer to the distributor. Who is the distributor to say that the Reconciliation Manager got it wrong? Itemised lists apportioning this across ICPs can obviously produced.

But it remains a fact that until the industry has sufficient confidence in its data reporting prowess to not need reconciliation, then in what way should a distributor consider the same data to be reliable, and why should the volume they invoice each trader for not match what the reconciliation manager said they used?

Q7. Are there other options you think the Authority should consider for improving peak period pricing?

As discussed earlier. Make it possible to have more granular timebands for ToU and allow prices to be set of a formula basis rather than a published set of absolute values. Requires changes to EIEP1 protocol (register content codes), EIEP12 (new price structure), the price detail that must be published on the website etc.

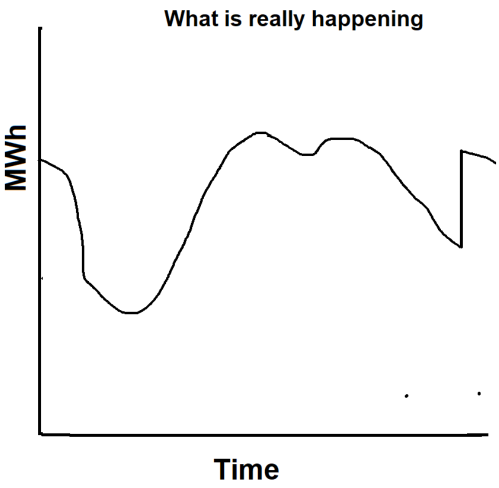
Either that, or continue to consider 14 hours of “day” timeband is sufficient to identify the trading periods the distributor wants the retailer to avoid,

Q8. Which if any of the above options do you consider would best support distribution pricing reform around peak pricing signals and why?

Make the changes that are needed to remove what is presently stopping distributors from passing on the price signals

Q9. Do you agree with the assessment of the current situation and context for off-peak pricing signals? What if any other significant factors should the Authority be considering?

Using “night” timebands, and an actual profile and the “proximity to congestion” approach to pricing, then night volume carries a small charge, based on the 11pm-1am pat being close to capacity,



If a more granular approach to timebands was taken (e.g. HHR) then 11pm to 1am could be priced based on proximity to congestion, the rest would be priced at $0 – no incremental cost per kWh and no congestion to signal. If everyone moved their load to the zero times, such that congestion levels were threatened again, then the price would rise above zero.

The main issue is the concepts of day, night and shoulder are too coarse grained for the signals the distributor needs to send the retailer. The fact that the consumer may want a daily charge and an anytime plan is a retail issue; the Electricity Industry Act says that the retailer is the distributor’s customer and it is to them that the signal needs to be sent. We know from the lack of action in PowerSwitch, not changing from incumbent traders and not making the LFC decision, there is not a lot of quality decision making going on at the consumer side of the meter.

Q10. Do you agree with the problem statement for off-peak pricing signals?

Yes. Some distributors more than others. The ability to price at zero is generally constrained however by the size of the “night” timeband and its ability to approach congestion levels at the start and end, thereby providing an inefficient signal for overnight load e.g. EV charging.

Q11. Do you have any comments on the Authority’s preferred pricing for off-peak usage?

Can’t price night timeband at zero if the timeband spans trading periods under high load e.g. 11pm to 1am for hot water. Need to be more granular.

Allocation of fixed charges across ICPs is an entire consultation in itself.

Q12. Are there other options you think the Authority should consider for improving off-peak pricing?

Refer above

Q13. Which if any of the above options do you consider would best support distribution pricing reform around off-peak pricing signals and why?

Allow for more granular timeblocks or we can only continue to price night volume based on a weighted average of those trading periods approaching congestion and those not.

Q14. Do you agree with the assessment of the current situation and context for target revenue allocation? What if any other significant factors should the Authority be considering? Not enough time to comment
Q15. Do you agree with the problem statement for target revenue allocation? Not enough time to comment
Q16. Do you have any comments on the Authority's preferred pricing? Not enough time to comment
Q17. Are there other options you think the Authority should consider for improving target revenue allocation? Not enough time to comment
Q18. Which if any of the above options do you consider would best support distribution pricing reform around targeted revenue allocation? Not enough time to comment
Q19. Do you agree with the assessment of the current situation and context for connection pricing? What if any other significant factors should the Authority be considering? The last 10 years or so has involved substantial investment in irrigation. This placed strain on networks requiring capital upgrades to be bought forward. Irrigators managed to construct business cases acceptable to their banks for the loans needed and people accepted the situation. Is the electric vehicle charging industry that financially fragile it needs the entry costs reduced to make the business cases stack up? I can only comment on a CapCon structure that was involved in some 2019 modelling. A comfort limit for congestion was determined – based on (n-1) resilience, 5 years organic growth and 10% spare; versus the theoretical capacity of that part of the network. Each applicant was allocated a deemed load profile at times of ADMD, and the capital contribution as based on how far that deemed profile pushed total load past the comfort level. The CapCon modelled was therefore based on the amount of spare capacity that was removed – therefore bringing forward a network upgrade that was previously outside the five year window – but only if the area had capacity issues. The work was discontinued because it did not fit the policies and processes at the time, and there was generally not enough congestion to trigger it.
Q20. Do you agree with the problem statement for connection pricing? Only the observation that if through the price/quality path constraints, and penalties for poor SAIDI the Authority has made it impossible for a distributor to earn the money needed for the network resilience work, there are not a lot of places they can get it from. It is also not fair to make a new connection pay for the cost of as deep upgrade. For example, a business that desires 2MW supply for industrial heat being told "*this will push the GXP past its (n-1) resilience limit so that will be $35M for a new GXP*" It is also unfair to saddle existing customers with the $35M cost when they were doing the right thing, had reduced load and shifted peaks, and managed to keep the GXP within (n-1).
Q21. Do you agree with the Authority's preferred pricing approach for connection charges? Insufficient time to comment, other than new connections should not ride on the coat tails of existing connections but need to pay their way,

Q22. Do you have any thoughts on the complementary measures mentioned above and to what extent work on these issues could lead to more efficient outcomes for access seekers?

Canterbury-area capacity and location data has recently been published by EECA.

https://www.eeca.govt.nz/assets/EECA-Resources/Co-funding/South-Canterbury-Spare-Capacity-and-Load-Characteristics.pdf

Q23. Are there other options you think the Authority should consider for connection pricing?

Out of time to comment.

Q24. Which if any of the above options do you consider would best support distribution pricing reform in the area of connection pricing?

Out of time to comment.

Q25A. Do you agree with the assessment of the current situation and context for retailer response? What if any other significant factors should the Authority be considering?

8.4…(correlation between lines and energy peaks) … unless you are a summer peaking network, where energy congestion and lines congestion are counter-cyclical

8.7(b)(iii) GXP profiles – "If a user shifts the timing of their consumption, then this will alter input costs for all retailers" … It also changes the energy settlement volumes for all retailers as the Reconciliation Manager also does not see this change. But no-one seems to be bothered about that, and everyone accepts reconciled volumes as gospel for settlement despite this. The argument is one for accurate ToU metering rather than one regarding which particular trading period a particular kWh was used, in a single register analogue meter read once every two months.

8.9(a) "the strength of any price signals "

The strength of price signal depends on the extent of the congestion and the number of trading periods involved. Pricing after all is supposed to be cost reflective (cost neutral) and not contain surcharges or penalties. This may be why the price signal option has been completely ignored as part of the solution to the present congestion issues in the lower Waitaki Valley; why distributors are relying more on load control, and the entire "modern pricing" initiative is stalling; the signals cant be made big enough to make retailers respond, while staying within cost-reflective rules. After all, if a distributor has to build $35M of new GXP that is not the retailer's problem; in fact it is probably to the retailer's benefit as it lets them sell more electricity in the area. The possibility that it may be in the retailers' interests to not respond to, or to respond badly to, distribution price signals has not been considered in this consultation.

Unless the Authority intends to nationalise retailers, or prescribe with a threat of statutory management for those that do not comply, the Authority is stuck with what it has: independent companies trying to find a price/service point that differentiates them from the competition, attracts/retains customers and makes money. If the public are insisting on day-rate plus anytime volume plans, then the retailers have to offer these or the customer base will walk. And if that is what the public wants, no amount of public service advertisements, or influencers on TikTok are going to change this. And if some quite different plan is provided, with say tiered volume with the first 200 kWh per month bundled, or free hours, or a chance to win a trip to Fiji, or whatever, it is because the retailer has seen a marketing niche to explore. It has nothing to do with the distributor or how congested or otherwise the network might be.

Retailers have to see the price signals from the distributors, and it then has to be worth while doing something about it, in a context where they are also receiving signals from the energy markets and those signals are larger. A distributor can always remove a supply/load imbalance by turning off a feeder – uncomfortable but not an existential threat – but a distributor who has messed up the hedging and facing a very high spot price and consumers they cannot disconnect is in a very different place. It is clear which signal is of more importance to retailers.

Q25B. [***for retailers***]: What plans do you have for responding to distribution price signals as distributors reform their price structures? What barriers do you see to responding efficiently?

Q25C. [***for distributors***]: What plans do you have to increase the proportion of your customers that face time-varying charges (for example, making TOU plans mandatory for retailers whose end-users

Q26. Do you agree with the problem statement for retailer response?

The retailers do not listen to signals

(i) because they do not have to
(ii) competition noises are louder
(iii) energy signals can be an existential threat but distribution signals cannot
(iv) it is in the retailers' interests to force the distributor to make the investment and remove the congestion issue

Q27A. Do you have any comments on the Authority's preferred pricing?

"*8.20(A) Billing on actual half hourly usage*"

Billing from HHR readings aggregated into timebands is perfectly acceptable subject to prior comments

(i) Day, shoulder and night bands are not sufficiently granular to send the congestion message as the congestion period is shorter than the timeband. This is particularly so for the "night" timeband which approaches level of peal congestion at times of seasonal peak and the hot water is rippled back on
(ii) The Reconciliation Manager is the final arbiter of data quality. If the result of reconciliation is that the HHR values do not add up and something is wrong, then they do not add up and something is wrong.

Q27B. [***for retailers***]: What use do you make of deemed and residual profiles? Please explain the reasons for this. What barriers do you see to phasing out use of deemed and residual profiles?

No deemed. Residual for everyone the retailer does not provide HHR data, or HHE data aggregated into the timebands use for pricing. Why? For the same reason the reconciliation process exists.

Retailer data has issues, if the Reconciliation Manager says the retailers' volume is something else, and that is deemed the gospel data for settlement, then who is the distributor to disagree?[2]
Q28. Are there other options you think the Authority should consider for retailer response?
The fact that retailers are charting their on course, and finding marketing niches for their plans to differentiate from competitors gives hope that the retail market, in at last parts, is starting to work. That is the problem with having a child, you can teach them, train them, nurture them but it reaches a stage when they start to do their own thing. As stated several times in this submission, there is a reason that distributors have been slow to adopt the Authority's view of what a distribution price plan should look like. And that might be because no one is listening. Things that work: • Ripple control • Identify one or two kingpin users and come to an arrangement that gets them off the network at key times • Jawboning? (it worked with carless days, no-one has tried it with electricity yet) • Invest in batteries • Buy a mobile generator • Reallocate LV and HV open points to reallocate load around the network • Do the upgrade
Q29. Which if any of the above options do you consider would best support distribution pricing reform in the area of retailer response?
As commented previously, if a retailer can give a meter reading for an appliance separated into the timebands used for billing volume, then that part used during off-peak times will be billed at off-peak rates; potentially zero (based on timeband granularity). Smart meters are little computers. If they were designed, built and programmed to interact with sockets, or someone invented a socket-level plug-in wifi-enabled meter that controlled the socket using messages from the Smart Meter, and passed readings back to the Smart Meter then the information could be collected. The technology Is not there yet. Retailers may yet come to rue the day they set the AMI requirements at "remote reading" and "kill switch" and deployed the world's dumbest smart meters across 90% of NZ.

[2] Seriously, outside this process, I do these reconciliations for 20 retailers monthly. These reconciliations demonstrate where large retailers still produce estimates despite having HHR meters they can read monthly, and where the month's data does not revert to sanity at wash-up time. If you need examples, feel free to ask and I'll get the distributor's permission to discuss the detail. The data from retailers can be problematic and coming up with a process that immunised against this was a financial audit requirement several years ago. They were prepared to accept reconciled data as a base as the process had regulatory backing and could be verified as anchoring the retailer data (in total) against something real.