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Submissions
Electricity Authority
Level 7, ASB bank Tower
2 Hunter Street
Wellington

Submission: Decision-making and economic framework for distribution pricing methodology review

MainPower welcomes the opportunity to submit on the Electricity Authority's proposal dated 7 May 2012 on the decision-making and economic framework for distribution pricing methodology review.

Please note that MainPower is also one of the parties represented in the submissions provided by the Electricity Networks Association and PriceWaterhouseCoopers on the same consultation.

If you have any questions related to this submission please contact Joel Hung ((03) 311-8336), e-mail joel.hung@mainpower.co.nz.

Yours sincerely,

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Submission on Decision-making and economic framework for distribution pricing methodology review

MainPower New Zealand Limited (MainPower) is one of the parties represented in the Electricity Network Association's (ENA) submission on the consultation "Decision-making and economic framework for distribution pricing methodology review" dated 7 May 2012. In addition, MainPower is also one of the parties represented in PriceWaterhouseCoopers (PwC)'s submission to the EA to the same consultation. We support the views expressed in the submission made by both the ENA and PwC.

This submission to the EA contains MainPower's views on some issues that are further relevant for MainPower. The submission is divided into two sections: the first section outlines the nature of MainPower's operational business which provides contexts to MainPower's submission, followed by the second section with our responses to the questions.

MainPower Company Profile

MainPower is the electrical lines company based in North Canterbury covering 11,180 sq km of area from the Waimakariri River in the south to north of Kaikoura. It has a total number of 34,247 connections as on 31 March 2011, with Contact Energy (Contact) as the largest retailer in the local network with 70% of customers.

The company is 100% owned by the MainPower Trust, which in turn is 80% owned by the Qualifying customers (defined as all MainPower customers except the customers within the part of network formerly owned by the Kaiapoi Electricity Limited and the embedded network at the former Wigram Air Force base) with the community at large owning the remaining 20%. There is a longstanding involvement with the surrounding community, including immense public goodwill on the part of North Canterbury's public, and close relationships with the customers on MainPower's part.

Appendix Responses to Specific Questions

Question No.	Question	Response
Q 1	Do you agree with the Authority's interpretation of its statutory objective with respect to distribution pricing? If you agree, please explain why. If you do not agree, please explain how you consider the statutory objective should be interpreted with respect to distribution pricing and the reasons for your interpretation.	We do not necessarily agree with paragraph 4.1.8 that the EA will include "any efficiency effects that may arise from wealth transfers" when considering the efficiency benefits of competition for the benefit of consumers. The EA's own "Interpretation of the Authority's statutory objective" quoted in paragraph 4.1.5 points out the EA assesses benefits to consumers in aggregate. If this is such cases, any wealth transfer actions would have been precluded from the analysis in the first instance. Even if the wealth transfer causes a net overall benefit to the consumers, this may come with a high cost which will have to be shouldered by electricity participants and the same consumers somehow. Also the EA is trying to position distribution pricing in the overall context of workable competition in the New Zealand electricity market overall. As we point out below, we do not believe electricity distribution is by itself as a workably competitive industry, nor it will play a significant role in enhancing competition in the overall market. Paragraph 4.2.8 appears to imply the EA reserve the right to apply Part 4 of the Commerce Act in the context of how it impacts on the distributors' application of the pricing principles and guidelines. We believe the Commerce Commission is the primary statutory authority in having the say on how the Commerce Act should be appropriately applied, and the EA will be overstepping its statutory authority if it attempts to apply the Commerce Act with its own objectives. The EA needs to clarify that it will be relying on the Commerce Commission's interpretation if opinions on the Commerce Act are required in the context of considering distributors' pricing principles and guidelines.
Q 2	Do you agree with the above application of the three limbs of the statutory objective to distribution pricing? If not, why not, and are there other examples of how distribution pricing can influence competition, reliability and efficiency?	We believe the EA needs to make sure it is not relying on any particular innovation or measure when it considers how particular alternatives to reinforcing distribution supply capacity will impact on the pricing methodology. The EA believes that retail and generation retails may be distorted across different distributors' networks if the distribution charges passed on to some retailers are different from others. From our experience this is an issue that falls outside the distributor's control. Distributors have very little control over how the pricing plan is repackaged into the final retailer pricing plans: the only incentive for the distributor to control is to request the retailer to break down distribution line charge components on a consumer's charge invoice. Distributors also have very little influence on increasing competition in the New Zealand electricity market. A key to improve competition is improving generation and a more active electricity wholesale market as a result. Generation connected via distribution networks to the grid will seldom be built based on the connection costs offered by the relevant distributor: it is either the location that is conducive to generation (for renewable sources), or there are non-financial needs such as reinforcing supply security (for non-renewable sources).
Q 3	Do you agree that a market-based distribution pricing methodology would tend to promote efficiency in network use and in	The potatoes sale supply chain analogy employed by the EA is not entirely accurate to describe how the electricity market operates. For instance, there is competition between different transportation providers in shipping potatoes, however, it is only economically feasible to have a single distributor per area. This means that, in

	investment in distribution networks, generation, demand management and the electricity industry more generally? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	practice, it is impossible to develop a fully market-based distribution pricing methodology, because such methodology requires more than one distribution network in the same area competing for service. The EA and Commerce Commission could require the distributors to implement a more market-based pricing methodology, but this will be a market-like approach as opposed to the market approach. Even if a fully market-based distribution pricing methodology could be adopted, it will likely introduce drastically different outcomes depending if the charges are set on an ex-ante or ex-post basis. In theory, a market-based pricing methodology will charge consumers on an ex-post basis as this is the fairest way to fully recover the cost of investment in the network, but in practice, the consumer may instead reach an individual agreement to pay the distributor i.e. charges will be determined on an ex-ante basis, for instance, dividing the cost of laying the supply point at the consumer's premise over a period of 10 years and pay the cost NPV adjusted. This means even at the big picture level, there will be disagreements whether a particular market-based pricing methodology can be judged as promoting efficiency – it all comes down to the judgment call of the EA or indeed any individual concerned.
Q 4	Do you agree that market-based distribution pricing methodologies are likely to be more durable and stable than approaches involving administered charges? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	Disagree. From our response to question 3, we fear that all it takes for the pricing requirements to change is the judgment call of the decision maker. The pricing methodology could change very drastically in short order depending on short term conditions, and for a smaller-sized distributor such as MainPower, we face higher external pressures to change the pricing methodology after modifying our judgment calls as the number of decision makers is small. This means the prices under the market-based may not be as stable as the EA anticipated. In contrast, administered charges facilitate long term decision making by investors as the effects of short term market fluctuations are buffered out. This buffering of market forces act for the benefit of the consumers.
Q 5	Do you agree distributors should use pricing methodologies that give preference to market-based approaches to distribution charges wherever such charges will be efficient and implementation will be practicable? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	We do not agree it is necessarily efficient to apply a market-based approach to distribution charges. As per our comment on question 2 at best a market-like approach may be achievable. Even if a market-like approach is workable, consumers will likely face highly individualized line charges based on the location of the point of supply, the demand profile, and whether any demand-response technology is used. As the EA conceded in paragraph 5.3.5(a) one of the simpler ways to implement a more market-based charge is to distribute loss and constraints rentals. This takes care of the market cost of bringing the electricity to the NSP level. However, it does not give any indication on how the distributor line charges should be determined on a market-like basis. In addition, determining the shares of loss and constraints excess to distribute will still require extensive knowledge of substation load distribution, peak level, any demand-response technology is in use. In MainPower's case, such a methodology will come at the expense of a high transaction cost: an extensive set up cost, plus an ongoing commitment to continuous judgments to allocate loss and constraints rebates, not to mention loss and constraints rebates as determined at the GXP level and will require significant studies to align with our ICP-based pricing approach. We agree with the EA that pricing based on long-term contracts is a form of market-based approaches to charges that is feasible.

		However, we argue that its existence means there are commercial advantages, such as certainty in returns, already at work that makes it desirable for distributors. There is little justification for the EA to require distributors to consider such arrangement in every case, regardless whether it is economically or otherwise, before moving on to consider a more administrator-based approach.
Q 6	Do you agree the second, third and fourth ranked preferences should be for administrative approaches to distribution charges of exacerbators pay, beneficiaries pay and other charging options wherever such charges will be efficient and implementation practicable? If so, what are your reasons? If you disagree, what are your grounds for disagreeing?	We agree with the overall framework of approach, however, it is could be difficult to identify who are the exacerbators and beneficiaries respectively. Exacerbators are, in an ideal world, be the party that most caused the need for network reinforcements. However, what may be an exacerbator on a feeder today could become a beneficiary tomorrow if another consumer that is a greater exacerbator is connected, and the benefits from any works related to the new exacerbator's connection cancels out the cost of the new beneficiary. A particular point of supply could also act as both an exacerbator and a beneficiary. If the same consumer/generator has already been charged as an exacerbator, the same party should only be charged as a beneficiary on any behaviour that is clearly identified as a beneficiary. In practice, this will be a very difficult decision to make as the load or generation profile will be required to give a truly fair charging basis, and the EA will have to accept there will be room for imperfect decision, particularly for a smaller distributor such as MainPower. More importantly, when it comes to the investments in backbone feeders and zone substations, as MainPower has a mainly long and thin network, which exacerbator should bear the most cost becomes debatable. A substation upgrade may mean all customers connected through to the substation are now exacerbators, but to a different extent. An economically fair exacerbator-pays charge mechanism will run into the same issues as market-based charges, which is highly individual pricing structures and driving up the distributor's transaction costs.
Q 7	Do you agree these actions can exacerbate investment? Are there other actions and, if so, what are they?	The descriptions are generally accurate. However, any decision making on an ex-ante basis will run a risk of sudden technology innovations that result on drastic changes to cost drivers. Such a "game changer" technology may be long time in the making and finally become practical, or it is coming out of the blue aided by another seemingly unrelated technology. There may also sudden changes to consumer base that drives up the number and types of exacerbators. An example will be the reconstruction of the Canterbury region post-earthquake-wise: population movement, plus possible emergency of new industries in areas that were previously marked with rural or rural-service-based economic activities. This means that we only identify the exacerbators and their actions to a certain extent ranked by the level of confidence.
Q 8	Do you agree that exacerbators should be identified by determining which party or parties have the ability to act differently, thereby avoiding the need to augment the network? Is there an alternative	This will run into the risk of "picking the winning horse" when it comes to any technological solution aimed at reducing the need for augmenting the network. We may assume when a particular manner to act differently may deliver the best driver to reduce the need to augment the network, but it may turn out to be another solution which we might have missed. For instance, distributed generation may be assumed to be the winner, but some energy storage technologies may suddenly become technologically feasible and offer more sizeable savings to the exacerbating behaviours.

	approach? If so, please provide details.	
Q 9	Do you agree with the assessment of the price that should apply to exacerbators? Do you agree with the assessment of how exacerbators pay should apply in practice? Do you agree with the proposed approach for identifying the preferred option or options for applying exacerbators pay? Please provide explanations in support of your answers.	It is rare for distributors to consider choosing between SRMC and LRMC when devising tariffs. Unless there is good reason to adopt a demand-based charge, a consumption-based electricity charge system will most inevitably look at LRMC. We note that the EA has highlighted the PAWG's findings in paragraphs 5.5.20 and 5.5.21 of the LRAIC-based pricing. In particularly, the PAWG's note that "fixed component was designed so as not to affect customers' usage decisions" in paragraph 5.5.21. We disagree that this application of LRAIC-based pricing be made compulsory. There are good physical reasons to allow for a possibility of fixed charges to reflect consumers' load profile, which is to recover at the minimum costs that are fixed plus any variable costs that are outside the ones that can be made into pricing signals to shape consumers' behaviours.
Q 10	Do you agree these considerations should be taken into account under an exacerbators pay approach? Please provide an explanation in support of your view.	We are generally comfortable with the considerations. Most distributors, including MainPower, identify such considerations already in the existing pricing methodology.
Q 11	Do you agree that these ways can be used to identify beneficiaries? Are there others? If so, please provide details.	We believe the EA has to clarify exactly the definition of a beneficiary. Is it only certain classes of generators that do not act as exacerbators when they are connected to the distributor network, or any load or generator whose cost of connecting and running the connection is less than how the load or generator will benefit from having such connection? For example, a customer with a normal residential connection sitting next to a new irrigation connection that requires network reinforcement. It is likely the cost of reinforcement is more than paid for by the irrigation connection, and the residential connection is reaping the benefit of such reinforcement such as relieved supply constraints at peak demand hours. Does it now act as a beneficiary?
Q 12	Do you agree with the assessment of the price that should apply to beneficiaries? Do you agree with the assessment of how beneficiaries pay should apply in practice? Please provide an explanation in support of your answer.	We find the methodology could be highly ambiguous and potentially lead to confusion. In the backup co-generation connection example quoted in paragraph 5.6.15, one can argue the cost should be based on the lost time and production associated with failing to have the backup co-generation installed, rather than the cost of the next possible generation alternative. It could even be argued that the distributor should back out of charging such co-generation altogether if it is never intended to export any electricity to the distributor network i.e. any generation behaviour will have nil effect on the distributor network performance. Also related to the issue of beneficiary pays principle, paragraph 5.4.12 states that negative exacerbators should not be paid for the avoided cost of augmenting the network for it is inefficient to pay such generation that would have gone ahead anyway. Many distributed generation would qualify under this category. The paragraph may conflict with Schedule 6.4 of the Electricity Industry Participation Code that requires distributors share benefits of distributed generation with the generation owner. Additionally, there would be many prospective generation that will be negatively impacted by any decision not to pay negative exacerbators, and it will

		be exceeding difficult for the distributor to determine whether the private benefit exceeds the investment cost.
Q 13	Are there other alternative pricing options? Do you agree with the assessments of how incentive free and postage stamp pricing should be applied in practice? Please provide reasoning in support of your answer.	We are comfortable with these pricing options if the preferred options are not workable.
Q 14	Do you agree that the guidelines are consistent with the proposed decision-making and economic framework and therefore do not require any changes? If you agree please explain why and, if not, please explain why not.	Please see our comment on question 15.
Q 15	Do you consider that the pricing principles and guidelines are consistent with the proposed decision making and economic framework? If you agree, please explain why. If you disagree please explain why not and how the principles should be changed.	We disagree with the EA's assertion. Identifying exacerbators and beneficiaries is one step further from the requirements listed under the current guidelines, and this framework will have to be referred to in addition to the guidelines when pricing methodology is being developed in the future. To put it in another way, by reading the pricing principles and information disclosures guidelines, it is very difficult to come up with the economic framework as suggested in this consultation paper with our reading of the agreed framework. Also there is nowhere in the pricing principles that requires a market-based approach be the most preferred approach, followed by exacerbators and beneficiaries. Being subsidy free does not necessarily mean market-based approach. This means the principles and guidelines should be modified in wordings to reflect any agreed economic framework to be used for assessing the pricing principles.
Q 16	Do you agree that pricing principle (b) should be interpreted as implying that where an alternative charging option is required prices should be set in a manner that minimises the impact of the charge on the use of the asset? If you agree please explain why. If you disagree please explain why not and please state how you consider this principle should be interpreted.	We disagree. We believe the wordings on its own will not result in such interpretation if we do not read the economic framework into pricing principle (b). All the principle says is that the shortfall would be set with regards to consumer responsiveness, which is not related to how the charge will impact on the use of the asset.
Q 17	Do you agree with the Authority's proposal to use the economic framework for distribution pricing as criteria for assessing distributors'	Please see our comment on question 15 for our disagreement, and suggestion on modifying the pricing principles and guidelines to reflect the agreed economic framework.

	application of the pricing principles? If you agree, please explain why and, if not, please explain why not.	
Q 18	Do you have any comments on the proposed process for confirmation of the decision-making and economic framework and the Authority's review of distributors' pricing methodologies?	We wish to point out the EA should refer to PwC's submission on the same consultation paragraphs 9 to 15 about the issue related to the piecemeal approach that the EA has adopted on the distribution pricing economic framework[1]. We suggest the EA allow time for the distributors to become familiar with the pricing framework already developed, and measure whether the outcomes are consistent with the statutory objective of EA outlined in paragraph 4.1.2 of the consultation document. If, after a few years of letting the current framework operate, the EA consider the framework with the statutory objective, it can incorporate the economic framework into the revised pricing principles and guidelines.

[1] PwC, "Draft Submission to the Electricity Authority on Decision-making and economic framework for distribution pricing methodology review", paragraphs 9 to 15, "Concern over piecemeal approach to distribution-pricing regulatory-framework", pages 2-3.