22 March 2019

Submissions
Energy Markets Directorate
Ministry of Business, Innovation and Employment
By email: energymarkets@mbie.govt.nz

Electricity Price Review Options Consultation: Meridian and Powershop submission

Meridian and Powershop agree with and support the majority of the options currently favoured by the Panel. They are largely balanced and sensible and will go some way in furthering the Panel's aims of strengthening the consumer voice, reducing energy hardship, increasing retail competition, reinforcing wholesale competition, improving transmission and distribution, improving the regulatory system and preparing for a low-carbon future.

Our primary areas of disagreement with the Panel's preliminary views can be summarised briefly:

- **Option C6: Mass switching of long-term consumers** – We are concerned this option is based on trials in the UK, the full results of which are not yet known. We are also concerned the practical difficulties have been underestimated, that the costs of this option will exceed the benefits to customers, that it will deter competition and investment, and that it will ultimately encourage consumers to disengage from the market.

- **Option D2: Introduction of mandatory market-making obligations** – We are concerned this option will not improve the robustness of current market-making. It will also take considerable time to implement and seems likely to drive cost increases to consumers. Meridian is already working with the Electricity Authority, the ASX and others on an incentivised system that can be introduced more quickly and will, we believe, ultimately provide a better long-term solution from a consumer and cost perspective. Meridian believes that improvements in gas market disclosure are key to reducing uncertainty and tightening spreads in the ASX market – we are pleased to see the Panel's recommendations relating to improved disclosure at D1.

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- **Options E1 and E2: Issue a government policy statement on transmission pricing and on distribution pricing** – The introduction of Government Policy Statements will not assist in resolving the inherently complex and location-specific issues involved in transmission and distribution pricing. On the contrary, it will delay and complicate the work of independent regulators in both areas and risks permanently politicising key parts of an electricity sector with a critical role to play in enabling the transition to a low emissions economy. The potential costs to consumers are significant.

By way of more general comments:

- Several of the Panel's currently favoured options potentially require increases to the industry levy. As the costs of the levy form part of every electricity consumer's bill an assessment should be made before proceeding with these options of whether the related cost increases to consumers are offset by greater consumer benefits.

- The Panel's First Report identified that increases in distribution and transmission costs have contributed significantly and disproportionally to the electricity price rises faced by consumers in recent years. Yet as far as we can tell none of the options favoured by the Panel will do anything to contain lines cost increases. At best the Panel's options will defer or 'smooth' such increases. We ask the Panel to reconsider this issue. In particular, we ask the Panel to consider what more could be done to hasten the introduction of cost reflective network pricing. The potential savings to consumers have been repeatedly estimated as running into billions. More immediately, as discussed at Option E3, the Panel's First Report identified scope for an immediate saving of an average $90 per annum per consumer (roughly 4.5% of an average bill) if distribution costs allocated to household consumers were aligned more closely and fairly to those households' actual network use.

Our detailed comments are set out in the attached submission document. Please contact me if you have any questions.

Yours sincerely

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Electricity Price Review Options Consultation: Meridian and Powershop Submission

Summary table

The table below summarises the Meridian view in respect of each of the Panel's preliminary views. Where the Meridian view and the Panel preliminary view are aligned or where we do not substantially disagree with the Panel we do not comment further. Where the Meridian view differs from the Panel preliminary view we have provided more detailed comments below.

#	Option	Panel preliminary view	Meridian view
Strengthening the consumer voice			
A1	Establish a consumer advisory council		
A2	Ensure regulators listen to consumers		
Reducing energy hardship			
B1	Establish a cross-sector energy hardship group		
B2	Define energy hardship		
B3	Establish a network of community-level support services to help consumers in energy hardship		
B4	Set up a fund to help households in energy hardship become more energy efficient		
B5	Offer extra financial support for households in energy hardship		
B6	Set mandatory minimum standards to protect vulnerable and medically dependent consumers		
B7	Prohibit prompt payment discounts but allow reasonable late payment fees		
B8	Explore bulk deals to social housing and/or Work and Income clients		
Increasing retail competition			
C1	Make it easier for consumers to shop around		
C2	Include information on power bills to help consumers switch retailer or resolve billing disputes		
C3	Make it easier for consumers to access electricity usage data		
C4	Make distributors offer reasonable terms		
C5	Prohibit win-backs		
C6	Helping non-switching consumers find better deals		
C7	Introduce retail price caps		

#	Option	Panel preliminary view	Meridian view
Reinforcing wholesale market competition			
D1	Tough rules on disclosing wholesale market information	favoured	favoured
D2	Introducing mandatory market making obligations	favoured	not favoured
D3	Make generator-retailers release information about the profitability of their retailing activities	favoured	favoured
D4	Monitor contract prices and generator costs more closely	favoured	favoured
D5	Prohibit vertically integrated companies	not favoured	not favoured
Improving transmission and distribution			
E1	Issue a government policy statement on transmission pricing	favoured	not favoured
E2	Issue a government policy statement on distribution pricing	favoured	not favoured
E3	Regulate distribution cost allocation principles	undecided	favoured
E4	Limit price shocks from distribution price increases	undecided	not favoured
E5	Phase out low fixed charge tariff regulations	favoured	favoured
E6	Ensure access to smart meter data on reasonable terms	favoured	favoured
E7	Strengthen the Commerce Commission's powers to regulate distributors' performance	favoured	favoured
E8	Require small distributors to amalgamate	not favoured	favoured
E9	Lower Transpower and distributors' asset values and rates of return	not favoured	favoured
Improving the regulatory system			
F1	Give the Electricity Authority clearer, more flexible powers to regulate network access for distributed energy services	favoured	favoured
F2	Transfer the Electricity Authority's transmission and distribution-related regulatory functions to the Commerce Commission	not favoured	not favoured
F3	Give regulators environmental and fairness goals	not favoured	not favoured
F4	Allow Electricity Authority decisions to be appealed on their merits	not favoured	not favoured
F5	Update the Electricity Authority's compliance framework and strengthen its information-gathering powers	favoured	favoured
F6	Establish an electricity and gas regulator	undecided	undecided
Preparing for a low-carbon future			
G1	Set up a fund to encourage more innovation	undecided	not favoured
G2	Examine security and resilience of electricity supply	favoured	favoured
G3	Encourage more co-ordination among agencies	favoured	favoured
G4	Improve the energy efficiency of new and existing buildings	favoured	favoured

= favoured = undecided = not favoured

Accompanying this submission are reports from:

- CEG on *Market making obligations in New Zealand;* and
- Professor Stephen Littlechild on *Ofgem's collective switching trial and possible application in New Zealand.*

Detailed feedback

A – Strengthening the consumer voice

A2 – Ensure regulators listen to consumers

The Panel is undecided on this option. Meridian believes option A1 is a far more effective way of achieving what's intended here i.e. requiring that regulators "*seek input from representatives of different groups of consumers*."

B – Reducing energy hardship

B7 – Prohibit prompt payment discounts but allow reasonable late payment fees

The Panel is in favour of this option and Meridian agrees.

Meridian made the decision to replace prompt payment discounts (PPDs) shortly prior to release of the Panel's First Report in October last year. Initially we moved to a guaranteed discount and have more recently moved to simply offering lower rates that 'bake in' the value of any discount.

Despite media reports suggesting otherwise, Meridian has not introduced a late payment fee for residential customers, increased credit checking, or tightened our customer credit criteria.

Almost 6 months have passed since our decision to replace PPDs and we have observed no discernible impact on, or deterioration in customers paying their bills late, levels of customer debt, or disconnections.

Meridian does not support and cautions against the extension of any ban on PPDs to other types of discount such as paperless bill discounts, direct debit discounts or bundled offer discounts. We understand the concern with these is not that there is anything wrong with such discounts in themselves but that they may become a means of gaming a ban on PPDs. We believe the same thing could be accomplished by the careful drafting of any ban.[1]

We are also concerned that banning bundled offer discounts risks reducing innovation and driving wider unintended consequences, while at the same time doing nothing to reduce energy hardship.

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[1] For example, a ban on PPDs could simply provide:

> **Clause 1**
> A retailer or distributor may not include a Prompt Payment Discount in an electricity contract with a consumer.
>
> **Clause 2**
> A retailer or distributor may only include a Late Payment Charge in an electricity contract with a consumer if the value of the Late Payment Charge does not exceed an amount which is a reasonable estimate of the cost to the retailer or distributor, as applicable, resulting from the consumer's failure to pay an invoice by a specified date.
>
> **Clause 3**
> In clauses 1 and 2:
> - ***Prompt Payment Discount*** means a condition of a contract which discounts the amount payable by a consumer, in respect of an invoice for electricity supplied, if the consumer pays that invoice by a specified date.
> - ***Late Payment Charge*** means an additional fee payable by the consumer if an invoice is not paid by a specified date.

C – Increasing retail competition

C5 – Prohibit win-backs

The Panel favours this option. Meridian does not. Meridian remains of the view that win-backs work to the benefit of consumers and that assertions of detrimental competition impacts do not withstand scrutiny.

With 36 retailers servicing the electricity market currently, or one for every 60,000 households, New Zealand has one of the most intensely competitive markets in the world. We out-perform markets in Australia (where New South Wales has the most retailers and there is one retailer for every 160,000 households) and in the UK (where there is one retailer for every 420,000 households). By this measure the New Zealand market is almost 3 times as competitive as Australia and over 7 times as competitive as the UK. The barriers to new retailers coming into our market seem to be lower than elsewhere and there are roughly twice the number of retailers in New Zealand than there were 5 years ago and three times the number of 10 years ago.

Further, once they have entered the market, retailers in New Zealand have achieved significant and substantial growth. In 2018 Electric Kiwi won the Deloitte Fast 50 award for the fastest growing retail or consumer products business in New Zealand – this is across all sectors of the economy.[2] This suggests that other retail and consumer products markets in New Zealand could take a leaf from the book of the electricity market in enabling new companies to successfully grow. Less anecdotally the combined market shares of more recent entrants is up 550% in the past decade and 260% in the past 5 years. This goes against claims of competition being negatively impacted. Recent advisory group investigation findings reinforce this view.[3]

In describing experiences with win-back restrictions in the telecommunications sector, the Panel suggest that these have contributed to 'strong competition' in that sector with 20,000 switches taking place per month (page 16 of the Options Paper). As an overall switching rate this equates to around 4 percent per annum, measured across around 5.3 million mobile and land connections. The comparable electricity market switching rate is 21 per cent. This suggests that 'win-back' rules may offer little value-add within an electricity market context.

Provided the rules are the same for all retailers however, we can and will adapt to whatever the Panel ultimately recommends.

C6 – Help non-switching consumers find better deals

The Panel favours this option. Meridian does not.

As proposed, this option would potentially involve switching customers to a retailer without those customers' express consent.[4] This is, as far as we are aware, unprecedented anywhere in the world. It would be highly intrusive and may well give rise to legal difficulties. Certainly there would be a high risk that such an option might prove to be extremely unpopular with consumers themselves.

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[2] Inclusive, for example, of manufacturing, financial services, technology, and food related industries. Refer for further details: https://deloitteprivate.co.nz/fast-50/2018-fast-50/2018-fast-50-results/

[3] Refer for further details the Market Development Advisory Group's (MDAG's) draft 'Saves and Winbacks' recommendations report, available: https://www.ea.govt.nz/dmsdocument/24918-saves-and-win-backs-updated-draft-recommendations-paper.

[4] Refer page 16 of the Options Paper which states: "Consumers could evaluate the savings … and *opt out* [italics added for emphasis] if they didn't want to switch". Secretariat staff have subsequently gone on to advise Meridian that that the opposite is intended.

We assume that what is actually intended, as per the UK approach on which this option is modelled, is an 'opt in' trial.

However even reframed as 'opt-in' Meridian is opposed. We asked Professor Stephen Littlechild to review this option and the UK experience. His report is included with this submission. He expresses a number of serious reservations which can be paraphrased as follows:

1. **Is the UK approach warranted in New Zealand?** The UK policy was driven by Ofgem in response to the UK Competition and Markets Authority's (CMA's) analysis and remedies. The CMA analysis was flawed but even if it had been right in relation to the UK it is questionable whether the NZ energy market is characterised by the same degree of problem as the CMA identified there. With the EPR's analysis suggesting otherwise[5], this gives cause to fundamentally question whether this proposed 'remedy' is appropriate here.

2. **Will consumers interests be served or will this drive disengagement and reduced innovation?** The CMA was concerned this option could encourage customers to remain disengaged in future. Moreover, collective switching of large numbers of accounts could cause confusion and disruption for customers and could limit innovation by suppliers.

3. **Will the benefits to consumers exceed the costs of the solution?** The costs and benefits need careful consideration. In the UK, the Cheaper Together policy of encouraging collective switching schemes cost nearly twice as much as the benefits secured from switching.

4. **Regulatory mass switches for all consumers + privacy issues + burdens on retailers?** There seem to be practical limits to collective switching. Is it actually feasible to offer collective switching to all the customers for whom this might be recommended? The burdens on regulatory agencies and on retailers need to be considered. Also important is whether this is a one-off trial or a continuing exercise. If it starts, when does it stop? Retailers in addition have legitimate concerns about collective switching. There are obvious concerns about privacy laws. Also, trials are costly, and require suppliers to invite their customers to leave. The latest trial in the UK was estimated to cost the retailer £30 million in lost revenues.

5. **Preferences around non-price attributes are also part of the equation.** It might be assumed that electricity and retailers are homogenous, so that switching is only about price. There are increasing challenges to this view, however. An analysis of the Big Switch in the UK concludes that consumers do not regard energy as a homogenous product and that opt-in collective switching processes do not deliver a panacea.

6. **Acknowledging the role of reputation and loyalty in consumer choice.** Consumers think they are choosing a retailer not a plan or tariff. Given the very different reputations of retailers, customers may be more prudent than the CMA realised. Reputation and customer loyalty are important. A regulator facilitating the transfer of customers to

[5] See, for example, page 13 of the Options Paper which states: "evidence shows New Zealand is more competitive than most, including Australia and Britain".

another retailer would need to consider, in addition, the quality of service, reputation, and likely future prices that would be charged by this retailer.

7. **Devaluation of and reductions in service quality.** If customers value service and good performance over time, how is this best identified? There is limited evidence in the UK trials to date that this was a consideration in proposing alternative suppliers. In one case a proposed supplier had the highest complaints ratio ever recorded, and went out of business some 18 months after being put forward in an Ofgem trial.

8. **The need for careful consideration of market-related impacts.** The impact on the market needs to be considered. For example, such a large scale transfer of a particular type of customers would likely have an impact on prices in the market. For some retailers, a transfer of large part of their customer base to another retailer could increase the average price necessary for them to cover total costs, and a shorter duration of stay could reduce the viability of offering lower prices to attract new customers. How can facilitating large-scale collective switches for disengaged customers be reconciled with encouraging customer loyalty to high quality and trusted suppliers? Bulk collective switches could favour suppliers able to absorb large quantities of customers at the expense of smaller or newer suppliers that are not able.

9. **The importance of initial trials.** It is important to engage in trials before committing to a policy of collective switching. How far the UK experience carries over to New Zealand remains to be discovered. And there are several respects in which UK evidence is lacking – for example, does collective switching encourage or discourage subsequent individual switching?

Other concerns we have are that this option will drive the market to a focus on price per unit at the expense of service, innovative products and offerings, and overall value. Retailers are unlikely to invest in innovation or service improvements when those investments are challenged by a process that seems focused only on price and encourages a retailer's most loyal consumers to switch.

Also, if this is a sensible regulatory approach for a highly competitive market like electricity retailing, then surely it should be extended out into other sectors the economy where competition is less fierce in a lot of cases? Would it really be appropriate to try to encourage mass switching of telco customers (for example) based only or largely on price? How about people who fill up at the same petrol station all the time? Or people who have been with the same bank all their lives? We suspect intervention of this nature by regulatory authorities into areas where consumers are already free to make their own choices may be resented by many.

The Panel seems fundamentally concerned about consumers remaining with the same retailer. As already adverted to, consumers reasons for doing so will vary, with brand loyalty and satisfaction with current service levels likely to be important factors in this decision. For many these will be far more important factors than nervousness or worry about switching and for these customers this option will be a solution in search of a problem. Seemingly intended to potentially service in the region of 400,000 to 750,000 consumers (see page 16 of the Options Paper) – that is, the headline group of consumers where there is no recent history of switching – the starting point for the Panel's analysis therefore needs to be re-considered. Meridian notes that even where customers stay with the same retailer they will not necessarily remain on the same plan.

Switching rates across households in New Zealand in addition are already high by international and domestic standards (refer C5 discussion above, focussing on the Telecommunications sector). As we noted in our submission to the Price Review's First Report, factoring in the consumers who actively investigate switching but opt not to do so increases the proportion of households who shop around to around 50 per cent.[6] Concentrating on headline numbers alone, New Zealand's household switching rate of 22.5% is higher than the 22.4% switching out-turn switching rate from Ofgem's early 2018 trial.

Given these factors, we do not believe this intrusive and costly measure is warranted.

Our strong preference is that the impacts of wider changes – for instance to enhance community-level network support services (B3) and facilitate bill switching 'prompts' (C2) – are first evaluated ahead of progressing the Panel's proposal for collective switching further. If it is to be pursued, Meridian recommends the concept is initially tested and evaluated through small-scale trials – with ex post reviews performed as part of this process, assessing, for example, savings realised, say two years following the switch. The results should then inform further cost benefit analysis which, in turn, can then inform decisions as to any more enduring arrangements.

D – Reinforcing wholesale market competition

D2 – Introduce mandatory market-making obligations

The Panel favours this option. Meridian favours instead the introduction of an incentive-based market-making scheme.

The Panel notes that an incentive-based scheme could be more efficient than a mandatory obligation, and compliance monitoring and enforcement costs could be lower. Meridian agrees and supports the introduction of an incentive-based scheme. The Panel's objection to an incentive-based scheme is that it "would take several years to develop". The Panel refers to the experience in Singapore where an incentive-based scheme has been introduced. Meridian understands that there were specific reasons, peculiar to the Singapore situation, that were responsible for the delay there. Meridian expects that an incentive-based scheme could be set up within a matter of months in New Zealand and much more quickly than a mandatory scheme.

As we noted in our submission to the Price Review's First Report the ASX is already working on an incentivised scheme.[7] The advantages of such a scheme include that it could potentially involve not just generators as market makers, but also the specialist electricity traders and financial intermediaries who currently speculate on the ASX NZ electricity futures market. We note that some energy traders who submitted on the First Report expressly confirmed their interest in participating as market-makers under an incentivised scheme. An incentivised scheme would also be more efficient as the competitive tendering of the market-making services enable them to be provided at lowest cost. An incentivised scheme would also mitigate any concerns around obligation evasion, the potential for excessive costs from a mandated obligation, and the precise calibration of UK-style stress provisions.

Meridian agrees with the Panel that participants should be able to buy or sell contracts during tight supply periods. As far as we are aware there is no evidence that participants have been prevented from doing so in New Zealand. The cost of contracts during such periods may be more than those

[6] Electricity Price Review: Meridian and Powershop Submission, page 4.
[7] Electricity Price Review: Meridian and Powershop Submission, page 49.

participants would ideally have preferred to pay, however that is a known risk in all markets, not just electricity, of choosing not to hedge earlier. As the Electricity Authority commented in its recent decision in respect of the undesirable trading situation unsuccessfully claimed by Electric Kiwi and others:[8]

> Purchasing hedge contracts after prices become volatile during a national gas shortage is inevitably a costly risk management strategy. It is also relevant to note that, even though bid ask spreads were wide during the investigation period, there was still significant volume of contracts traded, indicating that participants were still willing to transact.

While we disagree with the Panel's assessment that the ASX market is fragile (see our submission on the First Report) we nevertheless support steps to make market-making activity more robust provided the benefits to consumers of those steps are shown to outweigh the costs. As part of this we are pleased to see the Panel recognises that market-makers should not be required to assume undue risks. Even now, with voluntary market-making the costs to market-makers are significant. Meridian's market-making costs currently average approximately $1-2 million per annum and can grow significantly in volatile years. In the current financial year to date, market-making has cost Meridian over $5 million. Any market-making scheme that imposes costs like this without recompense effectively provides other ASX participants with access to the Meridian balance sheet (and the balance sheets of other market-makers) to support their own ASX trading – whether in the form of electricity derivative speculation by some ASX participants (e.g. investment banks and financial intermediaries) or straightforward hedging of spot market exposure by independent retailers and other electricity market participants.

We suggest the better approach would be for all participants in the ASX market to share the costs of market-making. If instead all costs are borne by the market-makers this means other participants will inevitably and continually criticise the existing arrangements (whatever they are), and push for more onerous obligations on market-makers, particularly at times of market stress. This comes at no cost to them and gives them greater optionality in their own trading or hedging activities, allowing them to leave trading or hedging decisions later, with lower risk to them and greater risk to market-makers. Some sharing of costs on the other hand would ensure that all ASX participants have incentives to seek the most efficient market-making arrangements that will ultimately be of most benefit to end consumers. Discussion about cost allocation should in our view happen regardless of whether a mandatory or incentivised scheme is preferred. If market-making is funded by all the beneficiaries of market-making (all ASX participants) this could be achieved through an industry levy or an increased ASX exchange fee.

Finally, and because the Panel has referred to the market-making experience in the UK, we have commissioned some work looking at those arrangements and looking generally at the issue of spreads widening during times of market stress. Accompanying this submission is a report from CEG. Key points of note include:

- Most markets, not just electricity futures, exhibit widened price spreads in periods of high price uncertainty i.e. this happens whether or not you have vertically integrated suppliers.

8 Para 9.96, Electricity Authority decision on claim of an undesirable trading situation: Claim submitted 8 November 2018 by Electric Kiwi, Flick Energy, Pulse Energy, Switch Utilities (Vocus), and Vector, 28 February 2019 ('Electric Kiwi UTS claim'), available at https://www.ea.govt.nz/code-and-compliance/uts/undesirable-trading-situations-decisions/15-september-2018/.

- The design of any intervention should therefore be free from the notion that there is a 'culprit' for widened spreads in the electricity sector who should be forced to bear the costs of interventions intended to reduce spreads.

- Establishing a mandatory market-making obligation would not in and of itself prevent wider spreads during times of high volatility as even under mandatory arrangements market-makers are not required to keep spreads tight all the time. New Zealand has a volatile wholesale market due to our hydrology, and at times there is genuine and significant uncertainty about future prices. Increased market-making that did not allow for this and permit widening of spreads once volatility reaches certain levels would present artificial certainty to ASX purchasers and transfer the risk and cost of real uncertainty to market makers, effectively subsidising other business models and disincentivising earlier hedging.

- The mandatory market-making model followed in the UK is not necessarily an appropriate model in a New Zealand context. In particular, it seems that NZ's current voluntary market-making framework is arguably more effective in dealing with volatility. The UK experience shows that:

    - Mandatory market-making obligations are costly, with market-makers incurring very high costs during periods of high price volatility. The costs of mandatory market-making would be far more pronounced in New Zealand given the relative volatility of the New Zealand wholesale market compared to the UK.

    - Recent structural changes have left the future of the UK market-making obligation in doubt.

    - The stress provisions used in the UK[9] would be triggered frequently if implemented in New Zealand (more frequently than NZ market makers have chosen to exercise the existing stress provisions under their current voluntary arrangement). Calibrating stress provisions in New Zealand is likely to be a complicated matter – with a very low stress threshold, the mandatory obligation is not a particularly binding constraint and may not achieve anything; with a very high stress threshold, the costs imposed on the obligated parties will be very high and may well exceed any wider benefit to consumers.

Finally we submit that any steps to improve market-making need to be accompanied by strong steps to improve gas market disclosure. We are pleased to see the Panel's recommendations to this effect at D1 of the Options Paper. See also our comments at F6 below.

D3 – Make gentailers release information about the profitability of their retailing activities

The Panel favours this option. Meridian also favours this option. We note that generator retailers are already required to provide segmental reporting under IFRS 8 "Operating Segments" and that the information released enables analysts and other interested stakeholders to assess the profitability of respective generation and retailing operations. We also disclose a transfer price. The relevant sections from Meridian's 2018 Integrated Report[10] are reproduced in Schedule 1.

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[9] The UK market-making obligation includes a suspension clause at 7(a), which states that: If, at any time in a trading window, a Product has been traded at a price which is more than 1.04 or less than 0.96 times the price at which the Product was first traded within that trading window, the licensee may decide to cease posting bids and offers for that Product for the remainder of that trading window. Ofgem recently considered changes to the licence conditions in order to ameliorate the costs incurred by market-makers during periods of high volatility, including a modification to clause 7(a) to allow market-makers to widen spreads when observed prices were 1.01 or 0.99 times the opening price.

[10] Available at https://www.meridianenergy.co.nz/assets/Investors/Reports-and-presentations/Annual-results-and-reports/2018/95098799a5/Meridian-Energy-Integrated-Report-for-the-year-ended-30-June-2018.pdf

E – Improving transmission and distribution

E1 – Issue a government policy statement on transmission pricing

The Panel favours this option. Meridian does not.

The Electricity Authority has been working on reforms to transmission pricing for a number of years and has conducted extensive consultation on each element of its proposal and several alternatives. It has signalled that it is now ready to move ahead with its process. The issuing of a government policy statement (GPS) at this stage would inevitably cause delay, probably requiring the Authority to reconsider and re-consult on its proposal in the light of the GPS. In other words, it would prolong the wait for a decision in the same way that other options considered and rejected by the Panel (transferring jurisdiction to the Commerce Commission, giving appeal rights on the merits etc) would prolong the wait for a decision. The Panel rejected those options in part because of the delay they would cause. We ask the Panel to reconsider and reject this option on the same basis.

The Panel says the extent to which transmission or any other shared national infrastructure prices should vary between users or regions is best settled with clear guidance from elected governments.

We are concerned that making the issue of transmission pricing permanently subject to guidance from the government of the day will mean it becomes politicised and never settled. Historically, the Minister of Energy prepared a GPS for the Electricity Commission, which was revised in 2002, 2003 (draft), 2004, 2005 (draft), 2006, and 2008.[11] There is a high degree of uncertainty and opportunity cost associated with such constant adjustment. Elected governments can and do change. The guidance issued by one elected government may be different from the guidance issued by the next. Even where governments don't change, what seemed appropriate to a government in its first term may change in later terms, with a new Minister, or new coalition partners. Every change in a government policy statement relating to transmission may trigger a full review of the Transmission Pricing Methodology (TPM)[12] and result in a re-allocation of transmission costs. The significance of the impact this would have for regulatory and investment certainty, given the scale of transmission costs annually ($941.85m for 2018/19), cannot be underestimated.

Another difficulty with the suggestion that "shared" national infrastructure prices should be settled via government guidance is that some transmission infrastructure is shared, and some is not. For the transmission infrastructure that is shared, the degree of sharing varies considerably. Much of New Zealand's recent transmission infrastructure has been built and much of New Zealand's future transmission infrastructure will be built to serve large population centres. Regional areas distant from large population centres may only derive benefit from it to a limited degree, if at all. Any GPS on this issue would therefore need to give clear guidance on what degree of cost sharing is required. This will be difficult without descending into the issues that the Electricity Authority has wrestled with in the course of its consultation on TPM reform.

It is not controversial to suggest, as the Panel does, that a reformed TPM should aim to avoid or minimise dramatic price increases. Both the Electricity Authority's previous proposal and its recent announcement indicate that the reformed TPM will contain a price cap to soften any price increases. At the same time any new TPM should, we believe, aim to drive more efficient use of the transmission network, reduce the need for future expenditure, and result in relatively lower transmission prices over time. Any TPM 'solution' that commits New Zealand to a series of

[11] Sapere Research Group *Electricity Sector Review 2018* paragraph 21.
[12] Clause 12.86 of the Code.

individually non-dramatic, but nevertheless steady, significant and continual electricity price increases, as a result of inefficient and wasteful transmission spend, is not in our view a good one.

The Panel welcomes comments on the Transpower draft GPS included with its submission to the Panel's First Report. We note that draft relates to regulation of the entire electricity sector and deals with a number of topics not related to transmission pricing. Focusing only on those parts of it that relate to transmission pricing we have supplied a mark-up in Schedule 2 of this submission. We have also included our suggestion for a GPS that deals just with transmission pricing.

As a general comment the Transpower draft contains a number of seemingly uncontroversial statements with which it is difficult to disagree. How far they go in resolving the difficult issues, as the Panel suggests any GPS must, is questionable. We also note the Panel has repeatedly said it is not the arbiter in the debate about alternative transmission pricing methods. What it will therefore do with the comments it receives on this issue is not apparent.

To be absolutely clear, Meridian does not agree that the issuing of a GPS would be constructive at this point in time. An independent regulator is far better placed to make durable changes to the TPM that will be efficient and of benefit to consumers in the long-term. We suggest the Electricity Authority as the independent regulator charged with resolving transmission pricing issues should be left to complete its process. That process is now close to a conclusion. To the extent that the current government or any future government disagrees with that conclusion it will be able to change it by legislation. However, inserting a GPS into the Authority's process at this point in time may, in our submission, effectively ensure the issues at the heart of the TPM are never fully resolved.

E2 – Issue a government policy statement on distribution pricing

The Panel favours this option. Meridian does not.

Many of the same points made in respect of option E1 also apply here. If as the Panel suggests, it is important that the issue of transmission pricing allocation, which makes up 10% of the average consumer's bill, is settled soon, it is arguably more important that the issue of distribution pricing allocation, which makes up 27.5% of the average consumer's bill, is also resolved soon. For our part, for the reasons already given above, we are doubtful that a GPS would be constructive.

E3 – Regulate distribution cost allocation principles

The Panel is undecided on this option. Meridian is in favour.

The Panel's First Report indicated that if distribution cost allocation was made more consistent with distribution network usage this would result in a reduction of approximately $90 in the annual electricity costs of the average household. In principle Meridian agrees that network cost allocation should be aligned with network usage. The Panel suggests this reallocation would need to be implemented by regulations and is concerned that this would be heavy-handed. Meridian's view is:

- it would be no more heavy-handed than some of the other options favoured by the Panel (for example C4, C5, C6, D2 or F1);
- such a move would also be consistent with well-signalled moves by the Electricity Authority to reform distribution pricing to ensure it is more cost reflective.

For some networks we anticipate the scope for re-allocation of costs to align with households' network usage will be limited. However, in those where there is such scope, we see no reason why the Panel would not favour this option. The onus could be placed on lines companies to demonstrate which side of the line their own cost allocation falls.

E4 – Limit price shocks from distribution price increases

The Panel is undecided about this option. Meridian does not favour it given the risk identified by the Panel that it may slow the development of distribution pricing that more accurately reflects costs and therefore reduce the expected efficiency benefits of distribution pricing reform.

E8 – Require small distributors to amalgamate

The Panel does not favour this option although it encourages more contracting, joint ventures and collaboration between distributors. Meridian acknowledges the force in the Panel's point that this option would potentially involve trampling on property rights.

However, Meridian remains concerned that the large number of distributors in New Zealand coupled with the lack of standardisation across the distribution sector is driving inefficiencies right across the electricity supply chain and raising costs for consumers. We are also concerned that a number of smaller distributors may not be well placed to handle significant technological change.

E9 – Lower Transpower and distributors' asset values and rates of return

The Panel does not favour this option.

Meridian agrees that the Panel is right to be concerned about changes that would impose unexpected losses on investors in lines companies and harm New Zealand's investment reputation. The same concern applies in respect of option E5 – Prohibiting Vertical Integrated Companies – and we note the Panel does not favour that option either.

Meridian also does not favour goal-driven revision of asset values or arbitrary reductions in the regulated rate of return. However, our submission on the First Report favoured lowering the percentile setting for regulated WACC from 67 to 50. Such a change is well within the bounds of the type of incremental adjustments that any investor in a regulated lines company might expect to see from the regulator – the Commerce Commission has previously considered it - and would do nothing to harm New Zealand's investment reputation.

We would like to see the Panel engage with this point in our submission and with lines company regulation more generally in more detail in its final report. The Commerce Commission (like the Electricity Authority) is entitled to considerable respect in its role as an expert regulator but not to complete deference, and we note that the Panel quote without testing it the Commission's assertion that the current percentile setting is justified because the risks of under-investment are greater than the potential harm of over-investment. This seems to be the sole justification for the current setting and was the same justification given when NZ embarked on Part 4 regulation almost 10 years ago. The Commission should by now have data on whether lines companies are under-spending on their networks, over-spending on their networks or getting it about right. This issue and its impact on prices paid by consumers both now and into the future goes to the heart of what the Price Review Panel is considering i.e. whether consumers are getting a fair deal from the 40% of their bills that pays for transmission and distribution lines and whether they will continue to get a fair deal into future.

F – Improving the regulatory system

F3 – Give regulators environmental and fairness goals

The Panel does not favour this option and Meridian agrees with the Panel. The Panel however favours giving the Electricity Authority a consumer protection function, in particular for the protection of household and small business consumers in hardship.

As we explain below Meridian considers that assigning this role to the Authority would create an unavoidable tension with its statutory objective to promote competition, reliability and efficiency in the electricity industry. Accordingly, the Authority would need to be given an express statutory warrant to act outside of its usual statutory objective in relation to such matters. This highlights that interventions designed to protect household and small business consumers in hardship are probably better made by Parliament directly, rather than by the Authority via the Electricity Industry Participation Code.

Statutory objective

The Authority's objective is set out in s 15 of the Electricity Industry Act 2010:

> The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

As the Panel has pointed out, adding protection of household and small business consumers to the present objective would "pull [the Authority] in too many directions, require difficult trade-offs between competing objectives and blur their accountability".[13]

Moreover, the present objective is well-understood and has provide a workable framework for the Authority's decision-making. The interpretation of s 15 has been elaborated on following industry consultation and is contained in the Authority's foundational documents.[14] This interpretation formed the basis for the Authority's work over the last eight years.[15] Amendment would undermine the certainty that has been achieved in this respect by potentially reopening issues which have been determined on the basis of the current objective.

Statutory functions

Meridian opposes including "protection of vulnerable consumers and protection against consumer hardship" as a function of the Authority in s 16 of the Act. Inclusion of a new function for this purpose will open an unnecessary and undesirable area of debate and uncertainty, namely that changes made by the Authority to the Code to implement consumer protection would potentially be open to challenge on the basis that they were not consistent with the statutory objective.

This issue arises because Code provisions must comply with s 32(1). Section 32(1) provides as follows:

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[13] Electricity Price Review *Options Paper* (18 February 2019) [**Options Paper**]at p 31. Such a move in addition would also be a reversal of the narrowing of the Authority's objective as a result of the 2009 review of the industry. The predecessor to s 15 was s 172N of the Electricity Act 1992. Section 172N was considerably more prescriptive in setting out the "principal objectives" and "specific outcomes" that the Electricity Commission was required to achieve. One of the objectives was "to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner". Widening the Authority's objective now would back-track on the deliberate narrowing of that objective in the 2010 legislation.

[14] Electricity Authority *Interpretation of the Authority's statutory objective* (14 February 2011) [**Interpretation Document**].

[15] The Authority describes it as one of its "key strategic statements": Interpretation Document at [1.1.3].

32 Content of Code

(1) The Code may contain any provisions that are consistent with the objective of the Authority and are necessary or desirable to promote any or all of the following:

(a) competition in the electricity industry:

(b) the reliable supply of electricity to consumers:

(c) the efficient operation of the electricity industry:

(d) the performance by the Authority of its functions:

(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.

In other words, s 32(1) requires Code amendments to be:

- consistent with the Authority's statutory objective (in s 15); and
- necessary or desirable to promote: the Authority's statutory objective; the performance by the Authority of its functions; and/or any other matter specifically referred to in the Act as a matter for inclusion in the Code.

It is not sufficient that a Code provision be necessary or desirable for the performance by the Authority of its functions; it must also be consistent with the Authority's statutory objective.

The Panel has recognised this and expresses the view that protecting consumers from hardship can be added as a function "without changing the Electricity Authority's objective because consumer protection is consistent with 'the long-term benefit of consumers'".[16]

However, this is not the correct test. The Authority's statutory objective is "*to promote competition in, reliable supply by, and the efficient operation of, the electricity industry* for the long-term benefit of consumers." The long-term benefit of consumers is the overarching purpose,[17] but to comply with s 15 a provision must first promote one or more of competition, reliable supply, and efficiency.[18]

While consistency with s 15 will depend on the particular consumer protection measure, there is no reason that such measures will necessarily (or even be likely to) promote competition, reliable supply or efficiency.[19] For example, a subsidy or a targeted price cap would tend to hinder rather than promote these limbs of the statutory objective.[20] Furthermore, an issue may arise as to whether such measures would be in the *long-term* benefit of consumers as a whole.

Expressly allowing Code provisions for consumer protection

If the Panel favours providing for consumer protection measures in the Code, Meridian submits that specific provision should be made for this in or around sections 42-44 of the Act. For example:

44A Consumer protection

(1) Without limiting section 32, the Code may provide for the protection of vulnerable consumers and protection against consumer hardship.

(2) Subsection (2) applies whether or not the provision in the Code is consistent with the objective of the Authority.

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[16] Options Paper at p 32.

[17] Interpretation Document at [A.1].

[18] See Interpretation Document at [A.12].

[19] This is not a criticism that can be levelled against the existing functions in section 16. Each of the existing functions in s 16 have little or no risk of conflicting with the statutory objective since they either have no policy content or the policy content is clearly aligned with the statutory objective.

[20] Any measure aimed at consumer protection would be subject to potential challenge on the basis that the amendment was not consistent with the Authority's statutory objective. See *Vector Ltd v Electricity Authority* [2018] NZCA 543 at [50]-[52].

Wording to this effect would bring Code provisions relating to consumer protection within s 32(1)(e). It would also preclude legal arguments that the measures are not permitted because they are or may be inconsistent with the Authority's objective in s 15. .

Finally, while it would be technically possible to empower the Authority to protect consumers in this way, we query whether it is desirable to do so given that a decision-maker ought not to be given objectives that potentially conflict. Furthermore, it is not clear what should guide the Authority once it is acting outside the statutory objective. For these reasons Meridian submits that any interventions designed to protect household and small business consumers in hardship are probably better made directly by Parliament, rather than by the Authority.

F5 – Update the Electricity Authority's compliance framework and strengthen its information-gathering powers

The Panel favours this option. Meridian agrees with this recommendation insofar as it relates to the Authority's information-gathering powers. In relation to the proposed greater separation of the Authority's rule-making and enforcement functions we aren't convinced of the need for this and would ask that any changes be subjected to full cost benefit analysis as they would almost certainly increase the Authority's costs and therefore costs to consumers.

F6 – Establish an electricity and gas regulator

The Panel is undecided about this option. Meridian is neutral provided that immediate steps are taken to address the current information asymmetry in relation to gas market information disclosure. We are concerned this is having an ongoing detrimental effect to the operation of the electricity market and support the Authority and Gas Industry Company's (GIC's) efforts to ensure greater transparency. If those efforts are unsuccessful or fail to proceed quickly enough the issue of a joint regulator would need to be looked at. We note that the current GIC consultation seems unlikely to produce any improvements in disclosure prior to 2020.[21] Meridian believes this is not quick enough.

G – Preparing for a low-carbon future

G1 – Set up a fund to encourage more innovation

The Panel is undecided about this option. Meridian does not favour it. There are already a number of funds supporting innovation in the sector as listed in the Options Paper. An additional available fund not listed is the EECA low emission vehicles contestable fund.

[21] The GIC is yet to advise what the potential timeframes for implementation could be. However, given the GIC is only in the initial stages of consulting on potential options, a target implementation date within the current calendar year appears unlikely.

SCHEDULE 1 (OPTION D3) – EXCERPTS FROM MERIDIAN'S 2018 INTEGRATED REPORT

A1 SEGMENT PERFORMANCE. The Chief Executive (the chief operating decision-maker) monitors the operating performance of each segment for the purpose of making decisions on resource allocation and strategic direction.

The Chief Executive considers the business according to the nature of the products and services and the location of operations, as set out below.

New Zealand Wholesale

- Generation of electricity and its sale into the New Zealand wholesale electricity market.
- Purchase of electricity from the wholesale electricity market and its sale to the NZ Retail segment and to large industrial customers, including New Zealand's Aluminium Smelter (NZAS) representing the equivalent of 40 percent (30 June 2017: 38 percent) of Meridian's New Zealand generation production.
- Development of renewable electricity generation opportunities in New Zealand.

New Zealand Retail

- Retailing of electricity and complementary products through two brands (Meridian and Powershop) in New Zealand.

  Electricity sold to residential, business and industrial customers on fixed-price, variable-volume contracts is purchased from the Wholesale segment at an average annual fixed price of $73-$78 per megawatt hour (MWh) and electricity sold to business and industrial customers on spot (variable-price) agreements is purchased from the Wholesale segment at prevailing wholesale spot market prices.

  Agency margin from spot sales is included within 'Contracted sales, net of distribution costs'.

  The transfer price is set in a similar manner to transactions with third parties.
- Powershop New Zealand provides frontline customer and back-office services for Powershop Australia. Revenue of $4 million has been recorded in 'other revenue' and is eliminated on Group consolidation.

Australia

- Generation of electricity from Meridian's two wind farms and three hydro power stations, and sale into the Australian wholesale electricity market.
- Retailing of electricity through the Powershop brand in Australia.
- Development of renewable electricity generation options in Australia.

Other and unallocated

- Other operations that are not considered reportable segments, including licensing of the Flux Federation-developed electricity and gas retailing platform.
- Activities and centrally based costs that are not directly allocated to other segments.

The financial performance of the operating segments is assessed using energy margin and EBITDAF (see page 89 for a definition of these measures) before unallocated central corporate expenses. Balance sheet items are not reported to the Chief Executive at an operating segment level.

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A1 SEGMENT PERFORMANCE *continued*

	NZ WHOLESALE		NZ RETAIL		AUSTRALIA		OTHER AND UNALLOCATED		INTER-SEGMENT			
		RESTATED		RESTATED		RESTATED		RESTATED		RESTATED		RESTATED
	2018 $M	2017 $M	2018 $M	2017 $M	2018 $M	2017 $M	2018 $M	2017 $M	2018 $M	2017 $M	2018 $M	2017 $M
Contracted sales, net of distribution costs	**435**	354	**629**	614	**98**	71	**–**	–	**–**	–	**1,162**	1,039
Virtual asset swap margins	**(2)**	4	**–**	–	**–**	–	**–**	–	**–**	–	**(2)**	4
Net cost of acquired generation	**41**	(4)	**–**	–	**–**	–	**–**	–	**–**	–	**41**	(4)
Generation spot revenue	**1,039**	684	**–**	–	**72**	48	**–**	–	**–**	–	**1,111**	732
Inter-segment electricity sales	**535**	506	**–**	–	**–**	–	**–**	–	**(535)**	(506)	**–**	–
Cost to supply contracted sales	**(1,259)**	(753)	**(470)**	(460)	**(84)**	(45)	**–**	–	**535**	506	**(1,278)**	(752)
Other market revenue/(costs)	**(6)**	(6)	**2**	1	**–**	–	**–**	–	**–**	–	**(4)**	(5)
Energy margin	**783**	**785**	**161**	**155**	**86**	**74**	**–**	**–**	**–**	**–**	**1,030**	**1,014**
Other revenue	**2**	4	**12**	13	**1**	–	**20**	9	**(13)**	(7)	**22**	19
Dividend revenue	**–**	–	**–**	–	**–**	–	**46**	1	**(46)**	(1)	**–**	–
Energy transmission expense	**(122)**	(125)	**–**	–	**(5)**	(5)	**–**	–	**–**	–	**(127)**	(130)
Gross margin	**663**	**664**	**173**	**168**	**82**	**69**	**66**	**10**	**(59)**	**(8)**	**925**	**903**
Employee expenses	**(28)**	(28)	**(31)**	(32)	**(9)**	(8)	**(27)**	(25)	**–**	1	**(95)**	(92)
Electricity metering expenses	**–**	–	**(31)**	(30)	**–**	–	**–**	–	**–**	–	**(31)**	(30)
Other operating expenses	**(56)**	(54)	**(34)**	(33)	**(29)**	(25)	**(22)**	(18)	**8**	6	**(133)**	(124)
EBITDAF	**579**	**582**	**77**	**73**	**44**	**36**	**17**	**(33)**	**(51)**	**(1)**	**666**	**657**
Depreciation and amortisation											**(268)**	(264)
Impairment of assets											**(2)**	(10)
Gain/(loss) on sale of assets											**7**	(4)
Net change in fair value of electricity and other hedges											**(23)**	(76)
Operating profit											**380**	303
Finance costs											**(82)**	(79)
Interest income											**1**	2
Net change in fair value of treasury instruments											**(3)**	55
Net profit before tax											**296**	**281**
Tax expense											**(95)**	(81)
Net profit after tax											**201**	**200**

Reconciliation of energy margin

Electricity sales revenue	**1,825**	1,483	**1,201**	1,131	**249**	193	**–**	–	**(535)**	(506)	**2,740**	2,301
Electricity expenses, net of hedging	**(1,042)**	(698)	**(553)**	(517)	**(100)**	(63)	**–**	–	**535**	506	**(1,160)**	(772)
Electricity distribution expenses	**–**	–	**(487)**	(459)	**(63)**	(56)	**–**	–	**–**	–	**(550)**	(515)
Energy margin	**783**	**785**	**161**	**155**	**86**	**74**	**–**	**–**	**–**	**–**	**1,030**	**1,014**

SCHEDULE 2 (OPTION E1) – DRAFT GPS

Meridian draft GPS

Draft GPS on transmission pricing

Introduction

This statement is given to the Electricity Authority as a statement of Government policy on transmission pricing. It describes how the Electricity Authority should prepare guidelines for setting transmission prices.

Background

The Electricity Authority is responsible for issuing guidelines on transmission pricing, and approving Transpower's transmission pricing methodology.

The Electricity Authority (and its predecessor Electricity Commission) has sought to reform transmission pricing since 2009. The Government acknowledges that the present transmission pricing methodology generates poor price signals, which results in inefficient use of, and investment in, the grid. Current transmission charges do not reflect the cost or service that is being provided, and the present methodology is not durable.

Government objectives for transmission pricing

The Government's objectives for transmission pricing are that:

- Transmission pricing should contribute to fair and affordable charges to end customers.
- Transmission services should be priced in a manner that promotes competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- The present transmission pricing methodology should be replaced and the Electricity Authority's reform of transmission pricing should continue without delay so that a new transmission pricing methodology can be in place within two years.
- The guidelines developed by the Electricity Authority for a transmission pricing methodology should be consistent with the specific objectives described below.

Specific objectives

The following objectives should be promoted by the Electricity Authority in developing guidelines for a transmission pricing methodology, and in approving the methodology developed by Transpower:

Overall principles

- Transpower's transmission charges should recover the full economic costs of its services.

- The cost of each transmission service should, where feasible, be charged to those customers receiving the benefits of the service.
- The price level for each transmission service should reflect the cost of delivering the service.
- Transmission pricing should facilitate scrutiny over proposed transmission investments.
- The Electricity Authority's guidelines should promote efficient pricing while at the same time should be reasonably practicable to implement and should promote certainty.
- The Electricity Authority's guidelines should ensure that a new transmission pricing methodology avoids price shocks particularly for vulnerable geographic regions or groups of customers.

Specific features

- The costs of connection to the grid should continue to be market-like, service-based and cost-reflective.
- The cost of interconnection assets should ensure that transmission pricing treats HVDC and HVAC assets consistently.
- To the extent that there remain residual costs of transmission, these costs should be allocated to load customers.
- Transmission pricing should provide for a prudent discount policy or equivalent, where efficient.
- Transmission pricing should apply to existing and new assets equally. A new TPM that applied only to new assets would perpetuate all of the existing problems, result in additional complexity and create an unhelpful precedent for future regulatory reform.

Meridian mark-up of Transpower draft GPS

[Transpower's draft GPS covers a number of things besides network pricing. The 'Drafting note' at the start of the Transpower draft along with the sections headed 'Introduction', 'Vision for the electricity sector', 'Priorities for the electricity sector', 'Specific regulatory priorities', and 'Enabling sector participants' have all been omitted from the mark-up below which just responds to the section of the Transpower draft GPS headed 'Investment and price settings']

Draft GPS on Electricity Sector regulation

Investment and price settings

- Network pricing (both distribution and transmission) should:
    - contribute to fair and affordable charges to end consumers;
    - promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers;
    - provide for the recovery of the full economic costs of distribution and transmission services through prices which reflect the benefits of the service being received and the cost of delivering that service;
    - facilitate scrutiny over proposed transmission and distribution investments;
    - be ~~simple~~ reasonably practicable to implement and promote certainty; ~~understandable to a wide range of sector participants, implementable and operable with limited discretion in a way that avoids the sector being held back by disputes~~;
    - ~~be cost based and sensitive to the importance of signalling peak network usage, as this will promote greater utilisation of existing assets by flattening demand and deterring peak demand growth, delaying or avoiding the need for further network investment;~~
    - be transitioned ~~introduce change incrementally~~ in a way that avoids price shocks, particularly for ~~is sensitive to the impact on~~ vulnerable regions or groups of consumers~~, and limits the potential for unintended consequences~~;
    - apply to existing and new assets equally – a new TPM that applied only to new assets would perpetuate all of the existing problems, result in additional complexity and create an unhelpful precedent for future regulatory reform; and
    - in the case of transmission pricing: (a) remove the arbitrary distinction between the HVDC and HVDAC interconnection assets ~~be aimed at securing wide spread support for any change, including reference to a clear and complete cost benefit analysis;~~ (b) allocate residual costs of transmission to load customers; and (c) provide for a prudent discount policy or equivalent, where efficient.
    - ~~be focused on the future, and the pathway of generation and network~~

~~investment implied by New Zealand's climate change objectives including enabling new technologies that will change the role and consumption patterns of consumers.~~

- Reform of distribution pricing that is sensitive to alignment with the Transmission Pricing Methodology (TPM), the importance of signalling peak network usage, and the way that new technology will change the role and consumption behaviour of consumers.

- The present transmission pricing methodology should be replaced and the Electricity Authority's reform of transmission pricing should continue without delay so that a new transmission pricing methodology can be in place within two years. ~~Resolution of the TPM reform process within two years and in a way that clearly provides for the costs of the interconnected grid to be [socialised or personalised].~~

- Change to the investment framework to allow Transpower or Government support and funding for proactive transmission network investment where appropriate (for example, facilitating the pipeline of generation investment required by New Zealand's climate change response).

Ofgem's collective switching trial and possible application in New Zealand

Stephen Littlechild

19 March 2019

1. New Zealand's Electricity Price Review (EPR) *Options Paper* (18 February 2019) suggests as Option C6 the possibility of helping non-switching customers to find better deals by means of a regulatory facilitated bulk switching deal. It says that this scheme could be modelled on a recent trial by Ofgem in the UK, involving 50,000 customers, in which 22.4% of them subsequently switched and saved an average of £298.
2. The purpose of this paper is twofold. First, to explain in a little more detail what Ofgem has been doing in the way of such trials, and why it has adopted this policy. Second, to reflect on this approach and its pros and cons and possible application in New Zealand. The paper does not seek to argue for or against this approach, but rather to highlight some factors that would need consideration in deciding whether and how to apply it.

Opt-in or opt-out deals?

3. First a clarification. The EPR describes its proposal as follows. "The Electricity Authority or a contracted agent would negotiate a bulk deal for consumers who had not switched retailers for many years. Consumers could evaluate the savings of such a deal and opt out if they didn't want to switch." But is this really intended to be an opt-out deal? Or an opt-in deal?
4. Annex One to the present paper reproduces the section of the EPR paper that discusses Option C6. The EPR says that "Such a scheme could be modelled on a recent trial in Britain – a suggestion raised by distributor Vector."
5. This suggestion is in a report by Axiom Economics attached to Vector's submission. Axiom says that disengaged customers could be presented with an alternative offer, and this option could be on either an opt-in or opt-out basis. Axiom's discussion is under the heading "Auctions for passive customers". Ofgem's collective switching trial is used to substantiate the claim that "The concept of auctioning electricity retail customers is neither new nor unprecedented."
6. This could be misinterpreted. Ofgem's collective switching trial did indeed involve an auction carried out *for the potential benefit of* passive customers, if they opted to take advantage of it. But it did not involve auctioning electricity retail customers themselves, as would be the case with an opt-out deal.
7. For the Ofgem trial in question, customers were advised individually that the trial would take place and were given the option not to receive further details if they did not wish to learn more. Only 0.1% of customers opted out at this stage. Subsequently, for those customers that did not opt out of receiving details, the actual switching was on an opt-in basis. Eventually, 22.4% of customers either opted-in to accept this deal or actively chose another tariff available in the market or actively chose another tariff with their existing supplier. The remaining 77.6% of customers stayed on their existing tariff with their existing supplier.
8. Thus, the Ofgem trial did not involve customers opting out if they didn't want to switch. Rather, customers could opt out if they didn't want to receive details of switching. They had to opt-in to switch. As explained below, the CMA Energy Market Investigation that recommended Ofgem take action did consider and explicitly rejected an opt-out collective switch, although it was silent on opt-in collective switching.

9. It is assumed in this paper that the EPR wishes to consider an opt-in switch along the lines of the Ofgem trial.
10. If the EPR nevertheless does wish to consider an opt-out switch, such switches have not been trialled in the UK energy sector. However, there is experience in the US, particularly in the state of Ohio, which has been studied.[1] Providing permission has been granted, municipalities there can negotiate collective deals with competing suppliers, and a residential customer in such municipalities is then automatically supplied on the negotiated terms unless that customer opts out. In practice, over 90% of customers typically accept the negotiated deal and under 10% opt out.
11. However – and it is a significant however – municipal aggregation with opt-out switching is only allowed in municipalities that have previously put this proposal to electors in a primary or general election, and have received majority support for it. As of 2006, for example, 207 out of 1054 communities in Ohio had voted to pursue municipal aggregation. A few other US states have pursued municipal aggregation, notably Illinois, but the majority of states have not done so.
12. Opt-out negotiated deals are obviously more significant than opt-in deals, in a number of respects. (In particular, the majority of customers tend to accept the fall-back position rather than actively opting in or out.) The present paper does not discuss opt-out negotiated deals (except in the sense that some of the trials enabled customers to opt-out of receiving further information about available deals).

I OFGEM'S TRIALS AND RELATED POLICY

Origins in the CMA analysis and recommendations

13. Ofgem's policy is largely inspired by the CMA Energy Market Investigation, *Final Report*, 24 June 2016. This described what the CMA diagnosed as a problem of weak customer response in the domestic (residential) market. The CMA concluded that, for various reasons, not all customers were sufficiently engaged in the market to enable effective competition. In particular, not enough of them considered switching supplier. The CMA's aim was to increase customer engagement. It had two remedies particularly relevant to the present paper, namely *(1)* the establishment by Ofgem of a programme to provide customers – directly or through their own suppliers – with information to prompt them to engage; and *(2)* creating an Ofgem-controlled database of 'disengaged customers' on default tariffs, which could be made available to rival suppliers so that they could prompt these customers to engage in the retail energy markets. [2]

[1] Stephen Littlechild, "Municipal aggregation and retail competition in the Ohio energy sector", *Journal of Regulatory Economics*, 34, 2008, pp 164-194. See also David Deller et al, *Collective Switching and possible uses of a disengaged customer database*, CCP and University of East Anglia, August 2017 (a report commissioned by Ofgem), esp s 3.3 on US experience.

[2] The CMA also had some additional remedies for the retail market. It recommended substantial withdrawal and/or modification of Ofgem's "simple tariffs" restrictions, greater ability of Third Party Intermediaries to promote customer engagement, greater use of principles rather than prescriptive rules in addressing supplier behaviour, and a cap on Prepayment Meter (PPM) tariffs because of particular obstacles to competition associated with metering. Ofgem implemented that cap and then extended it to other (vulnerable) customers. The Government later required Ofgem to put in place a cap on Standard Variable Tariffs (SVTs) and default tariffs.

14. The CMA discussed the nature and implementation of these remedies in considerable detail. It placed emphasis on trials to see what worked and what didn't work. As regards the provision of information by suppliers, the CMA recommended that Ofgem "*(a)* establish an ongoing programme to identify, test (through randomised controlled trials (RCTs), where appropriate) and implement (for example, through appropriate changes to standard licence conditions) measures to provide domestic customers with different or additional information with the aim of promoting engagement in the domestic retail energy markets; and *(b)* introduce (following a consultation) a licence condition to require suppliers to participate in the Ofgem-led programme." (CMA *Final Report*, June 2016, para 13.20)
15. The CMA also recommended that Ofgem test aspects of the marketing communications by rival suppliers (e.g. as to form and frequency) in the context of the database remedy.

Database remedy

16. Following the CMA *Final Report*, on 3 August 2016 Ofgem published for consultation its proposed Implementation Strategy. On 9 November 2016 Ofgem confirmed its *Remedies Implementation Plan*.[3] On 30 January 2017 it introduced a new licence condition SLC 32A: Power to direct suppliers to test consumer engagement measures.[4]
17. Taking first the database remedy, the *Remedies Implementation Plan* proposed to "design, test and deliver a secure database service by April 2018". There were to be three phases: Alpha phase by February 2017, Private Beta phase by August 2017 and Public Beta phase by April 2018, with fully tested working service ready for national go-live in April 2018.
18. In July 2017 Ofgem announced a deferral of the Database target roll-out date until later in 2018.
19. On 13 November 2017 Ofgem asked suppliers to be ready to transfer data to it by April 2018. It planned to issue a Notice of Direction to large suppliers with over 250,000 customers on default tariffs for more than 3 years.[5] The aim was to provide adequate notice because this would entail "a significant data cleanse process for large suppliers". Ofgem was considering extending the Notice to smaller suppliers in summer 2018.
20. In October 2018 Ofgem is cited as planning "to publish the Directions relating to the implementation of the Disengaged Energy Customer Database before December 2018".[6] In the event, these Directions were not published in 2018, or to date in 2019. As of mid-March 2019 there seems to have been no further announcement about the Database.
21. I understand that suppliers are required to have formulated the data but have not yet been required to send it to Ofgem. Could the database be made available later in 2019, and used as

[3] https://www.ofgem.gov.uk/system/files/docs/2016/11/cma_remedies_implementation_plan.pdf

[4] "The scope can be summarised as: • the broad power to direct suppliers to test or evaluate (including via RCTs) any type of consumer engagement measure in a manner and timescale decided by Ofgem; • in the context of trials of consumer engagement measures, the power to direct suppliers to provide information to domestic consumers in a manner and timescale decided by Ofgem; • the power to direct suppliers to produce and submit a plan for conducting trials for engagement measures; • the broad power to direct suppliers not to comply10 with any relevant licence conditions, with or without enforceable requirements to comply with any alternative/replacement obligations relevant to the same subject matter (derogation power); and • the broad power to direct a supplier to provide Ofgem (or any other person) with information about the results of the trial (including underlying data)." (Ofgem Statutory Consultation, 19 October 2016, p 5)

[5] https://www.ofgem.gov.uk/system/files/docs/2017/11/20171113_open_letter_cma_database_remedy.pdf

[6] CMA, *SSE Retail and nPower, a report on the anticipated merger*, 10 October 2018, Appendix B *Customer Engagement*, para 76.

the basis for a major customer engagement and switching programme following completion of the various trials described below? If so, this would represent a merging of the two separate remedies recommended by the CMA, and the use of the database for a purpose not envisaged by the CMA – indeed, a use about which the CMA expressed reservations? This is discussed further in Section II below.

22. As of today, however, it is unclear whether or when such a database will be established and made available to other suppliers, and if so on what basis.[7] It is also unclear what powers Ofgem has, if any, to use the Database for purposes of large-scale collective switching exercises.

Database Trial

23. In late 2016, Ofgem carried out qualitative panel research looking at how customers might react to a database remedy. On 1 November 2017 it reported on the findings of that research.[8]
24. In late 2016 and early 2017, Ofgem conducted a small-scale Database Trial to test the effectiveness of such a remedy. It published the results on 1 November 2017.[9] The Database trial involved 2,400 customers (1200 from each of two suppliers) who had been on default tariffs (SVTs) with those suppliers for at least three years. Each customer was sent either (a) up to six marketing letters from other suppliers (generally two letters from at most three suppliers), as the CMA had envisaged under the 'Database Remedy'; or (b) one Best Offers Letter (BOL) from Ofgem, presenting three cheaper tariffs to them. There was also a control group that received no letters.
25. Customers (other than the control group) were notified on 23 November 2016 that they could opt out of receiving communications on energy deals. 2% of customers did so. Those who didn't opt out received the Best Offers Letter on 6 January 2017 or suppliers' marketing material throughout January.
26. The trial resulted in an increase in engagement for customers receiving marketing letters or Best Offers Letters: 6.8% of the control group switched supplier or tariff, 13.4% of customers receiving marketing letters from rival suppliers switched supplier or tariff, and 12.1% of customers receiving an Ofgem Best Offers Letter switched.
27. Ofgem noted that, in this trial, switching internally (i.e. to a new tariff with the same supplier) was more common than external switching. For example, in the group receiving marketing letters from suppliers, where 13.4% of customers switched supplier or tariff, 5% switched supplier and 8% switched tariff with their existing supplier. Ofgem conjectured that the letters prompted some customers to look on Price Comparison Websites [PCWs] or call their supplier to negotiate a cheaper tariff.
28. Ofgem commented that "Switching rate in the control group (6.75%) was higher than expected, and higher than recent market trends. This may be because of external factors: there was a well-publicised price increase during the trial and also there was a programme on

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[7] Interestingly, although Ofgem at one time highlighted collective switching, both the chairman and the CEO of Ofgem made speeches at Ofgem's Future of Energy Conference on 10 January, and neither of them mentioned the database, or this work programme generally. Nor did the new executive director for consumers and markets, in a keynote speech on 20 November setting out Ofgem's future energy vision. It has been suggested to me (not by Ofgem) that there may be a concern about legal challenge, including on data protection law. (See below)

[8] *Research paper on customer reactions to the database remedy*, at https://www.ofgem.gov.uk/system/files/docs/2017/11/ofgem_consumer_first_panel_wave_one_report_pdf.pdf

[9] Small scale Database trial, Summary of Findings, November 2017, at https://www.ofgem.gov.uk/system/files/docs/2017/11/small_scale_database_trial_slidepack_pdf.pdf

energy prices by Martin Lewis (an influential TV journalist and consumer champion)." Ofgem also noted that "a price increase notification issued by both suppliers during the trial may have also caused subsequent switches".

29. Note that these switching rates refer to switching either supplier or tariff, and more of these customers switched tariff than supplier. Thus, the (nearly) 7% switching rate for the control group comprised about 2% switching supplier and 5% switching tariff with the same supplier. For the other two groups, about 5% switched supplier and 7-8% switched tariff.
30. To put the external switching rates in context, the average annual switching rate in the market as a whole increased gradually from about 16% in 2004 to a high of 20% in 2008, fell gradually to half that level (10%) in late 2013 then increased gradually to about 15% by December 2016 and 20% by December 2018.
31. It is not known what level of switching the control group exhibited over a whole year. The switches in the months immediately preceding and following the trial seem to have amounted to roughly half the level during the trial. In the weeks just before and just after that, switching was negligible. So the rate of external switching (i.e. switching suppliers) was around 3% over that period, and may not have been much above that for the year as a whole. This is not implausible given that these customers had not switched externally for at least three years, possibly much longer.
32. Energy prices had been generally declining from 2014 to end 2016. But on 16 December 2016 EdF announced an 8.4% increase in electricity prices to take effect in March 2017, albeit accompanied by a 5.2% cut in gas prices. It was forecast to be "the first of many" price increases. Then on 3 February 2017 NPower announced a higher increase, which got much media coverage.

> Energy regulator Ofgem has said Npower must "justify" to its customers why it is introducing one of the largest energy price rises for years. The government also said it was "concerned" by the increase, while a former boss of Npower called the rise "shocking". The company will raise standard tariff electricity prices by 15% from 16 March, and gas prices by 4.8%. A typical dual fuel annual bill will rise by an average of 9.8%, or £109. Npower said the changes would only affect about half of its customers. The other half are on fixed-term deals and will see no price rise. The rise in electricity prices is thought to be the largest since 2008, when some suppliers increased charges by up to 19%. Some gas prices went up by a similar amount in 2011. Comparison website Uswitch said the rise for dual fuel was the largest for a big six supplier since 2013.[10]

33. The remaining large suppliers followed suit: Scottish Power on 10 February (effective 31 March), E.On on 7 March (effective 26 April), SSE on 13 March (effective 28 April) and British Gas in August 2017.

Initial trials (CMOL and CYED) of provision of information by suppliers

34. Turning now to the customer engagement programme, the *Remedies Implementation Plan* said that an initial series of randomized control trials would be completed by September 2018, after which Ofgem would "learn lessons and establish forward plan". On 8 June and 2 July 2017 Ofgem gave Notice of Direction to certain suppliers that it intended to carry out a series of trials, to which end the suppliers would be required "to carry out and refrain from certain activities". Details of these activities have not been published. On 14 August 2017 Ofgem

[10] "Npower facing backlash over energy price rises", https://www.bbc.co.uk/news/business-38852517, 3 February 2017

invited thoughts as to how to engage customers and carry out the trials. It also issued guidance on supplier-led trials. A series of trials has since been carried out.

35. A Cheaper Market Offers Letter (CMOL) Trial, with 75,000 customers from each of two large suppliers, was completed in summer 2017 and Ofgem reported results on 24 November 2017.[11] Briefly, this trial found that, when customers were sent a letter from their supplier or from Ofgem, with details of lower offers in the market, an average of 2.9% of customers switched supplier (compared to 1% of the control group that did not receive such a letter).
36. A 'check your energy deal' (CYED) trial took place in August 2017 and Ofgem reported results in February 2018.[12] Over 10,000 customers within the Northampton area were invited to see the three cheapest energy deals available to them based on their energy consumption. Trial customers could then switch by a dedicated CYED website or were given guidance in how to do so. The trial doubled switching rates compared to the control group, from around 2.6% to around 4.8%. Customers who switched after using the CYED service saved an average of £261.

The Collective Switch Trial

37. The Collective Switch Trial cited by EPR was initiated in February 2018.[13] Ofgem reported early findings in August 2018. [14] An extract from Ofgem's summary is reproduced in Annex Two to this paper.
38. Briefly, 50,000 disengaged customers of one large supplier (Scottish Power) were randomly selected. These customers had been on a Standard Variable Tariff with the same supplier for at least three years. On average they had been with their current supplier for six and a half years.
39. All customers in the trial were sent an Announcement letter about the collective switch. These customers could then opt-out of receiving details of the offer. Only about 0.1% of customers opted out from receiving such details.
40. Provided they did not opt out, these customers were sent details of an exclusive tariff negotiated by an Ofgem-appointed independent price comparison service (Energyhelpline). Unlike other switches, customers did not need to enter their existing tariff details in order to have their personal savings from switching calculated. Ofgem required that Energyhelpline be given all the participating customers' consumption data (plus name and address), so that it could thereby compare each customer's expected annual cost under the existing tariff and under any new tariff. (Consistent with standard Ofgem-guided practice, this assumed that tariffs and usage remain unchanged.) Customers received letters showing how much they could save by moving to the collective switch tariff.
41. Customers could contact Energyhelpline online or by phone to discuss any issues, and could also receive information about potential savings from other deals across the market. I understand that Energyhelpline's costs were paid by the suppliers gaining customers, under a deal negotiated by Ofgem.
42. A third and final communication was a reminder letter to all customers.
43. This trial had more striking results than previous ones. In total, 22.4% of trial participants opted to change their energy tariff. Over a quarter of these were over 75 years of age. This

[11] Cheaper market offers letter trial, at https://www.ofgem.gov.uk/system/files/docs/2017/11/cmol_report_0.pdf
[12] Check your energy deal, Final Findings, November 2018, at https://www.ofgem.gov.uk/system/files/docs/2018/12/cyed_final.pdf
[13] Active choice collective switch, February 2018, at https://www.ofgem.gov.uk/system/files/docs/2017/11/cmol_report_0.pdf
[14] https://www.ofgem.gov.uk/system/files/docs/2018/08/open_letter_collective_switch.v3finalnowm.pdf

switching rate was over eight times higher than the switching rate of the trial control group of 2.6%.

44. Participants changed their energy tariff in one of four different ways. Customers who switched to the Collective Switch tariff saved on average £261 a year. Customers who stayed with their present supplier but switched to a different (fixed) tariff saved on average £239 per year. The largest savings in the trial were made by customers who undertook an open market tariff search and switched through Energyhelpline, saving on average £352 a year. The average saving over these three modes of switching tariff was £298. A fourth group of customers switched to another supplier without going through Energyhelpline (so-called external direct switches). The average savings made by this group of customers is not yet public.
45. To put these savings in perspective for non-GB readers, the average annual dual fuel bill for an average customer (using 3100 kWh electricity and 12,000kWh gas per year) was a little over £1000 during this period.
46. The proportions of customers switching supplier versus switching tariff with their existing supplier is again important. Ofgem says "Approximately half of the switchers chose the collective switch tariff with another 40% moving to cheaper deals in the open market. Approximately 10% of this group [presumably, the group of switchers] chose another tariff with their existing provider." No information has been provided about the different kinds of switching of the control group.
47. Customers in this trial were contacted in three different ways. One set of customers (one "arm" of the trial) received the offer and reminder from Ofgem. The second arm received the offer from Ofgem and the reminder from the customer's own supplier that participated in the trial. The third arm received both the offer and reminder from the participating supplier. Customer switching rates differed markedly: on average 15.0% in the Ofgem-only arm, 18.5% in the Ofgem-supplier arm, and 26.9% in the supplier-only arm. This suggests that customers place value on evidence of approval or cooperation by their present supplier.

The Active Choice Collective Switch Autumn Trial

48. Ofgem's plans for further trials after the first Collective Switch Trial can be pieced together from information on its website and in the December 2018 High Court judgment described below. It seems that Ofgem originally envisaged "three trials of 100,000 [customers] each with two trials to be before the price cap". This refers to the Government's default tariff cap to be introduced on 1 January 2019. In August 2018 Ofgem announced that it "is planning a larger collective switching trial involving over 200,000 customers later this autumn". There was no reference to the third trial.
49. Then the timing of the two trials was modified. "The change was then to two waves of 100,000 customers to be conducted in the autumn trial, one to be before the price cap and one after. When it became apparent that the price cap level would not be [set?] until at the earliest early November 2018, it was concluded that the first test should be in 2018 before the price cap, and one following the introduction of the price cap in early 2019."[15]
50. The first of these next two collective switch trials took place from October 2018 to March 2019. Only brief details are presently available.[16] Ofgem says "we are testing whether we can achieve the same results on a larger scale and with more suppliers".

[15] December 2018 High Court judgment (see below) para 43.

[16] https://www.ofgem.gov.uk/consumers/household-gas-and-electricity-guide/how-switch-energy-supplier-and-shop-better-deal/ofgem-disengaged-customer-database

51. Ofgem continues: "Alongside this, we are also testing the open market comparison service without an exclusive tariff. We want to test how much impact the inclusion of an exclusive tariff has vs an open market search only. Both parts of the trial will show customers the personalised projected savings available to them. The results of the trial will inform our next steps, including our ongoing policy development process, which could include considering how we might bring the benefits of this approach to a wider range of disengaged energy consumers."
52. The results of the Autumn Collective Switch Trial have not yet been announced. Nor are there any details about the "next steps".

II REFLECTIONS ON REGULATORY FACILITATED BULK SWITCHING

Is the CMA analysis persuasive and applicable in New Zealand?

53. Ofgem's policy of facilitating bulk switching is claimed to address what the CMA diagnosed as the problem in the GB retail energy sector. The CMA concluded that weak customer response had an Adverse Effect on Competition, and that this imposed a customer detriment averaging £1.4bn per year (and £2bn in 2015). But is such a detriment plausible?
54. I have elsewhere challenged the CMA's diagnosis.[17] Briefly, there was no evidence that customers were less engaged in energy than in other sectors; the savings allegedly left on the table by disengaged customers depended greatly on what range of options were assumed acceptable to customers (e.g. ability and willingness to change payment method) and were lower for what seem more reasonable assumptions; the calculation of customer detriment used a hypothetical efficient and equilibrium benchmark inconsistent with the CMA's *Guidelines* that preclude using perfect competition as the benchmark; and the detriment calculation largely reflected the higher costs of the larger suppliers (which might have reflected their more onerous obligations and customer profiles relative to smaller suppliers) rather than any finding that they made excessive profits, which is inconsistent with previous practice by the UK competition authority. My critique therefore challenges the claim that GB customers are somehow unwilling to engage and were being taken advantage of, and need to be prompted to be more engaged in the energy market.
55. For New Zealand, a question is whether there is a competition problem in the retail energy sector of the nature and magnitude of the problem that the CMA perceived in GB. The EPR indicates that the situation in New Zealand is not as problematic as the CMA alleged in GB: "evidence shows New Zealand is more competitive than most [countries], including Australia and Britain" (p. 13) and "retail competition is working more effectively here than in Australia and Britain" (p 17). If this is the case, does New Zealand need this particular remedy that Ofgem has adopted?

Are there downsides to the facilitated bulk switching remedy?

56. Ofgem presents facilitated bulk/collective switching as a consequence of the CMA report recommendations. But closer inspection suggests that this was not what the CMA had in mind, and indeed the CMA had reservations about this approach.

[17] E.g. Stephen Littlechild, "Retail lessons for New Zealand from UK regulation and the CMA's Energy Market Investigation, including a critique of Professor Cave's analysis", 8 October 2018, as submitted to the EPR by Meridian and published with their submission. file:///C:/Users/user/Downloads/meridian-energy-electricity-price-review-first-report-submission.pdf

57. The CMA recommended that Ofgem "establish an ongoing programme to identify, test (through randomised controlled trials (RCTs), where appropriate) and implement (for example, through appropriate changes to standard licence conditions) measures to provide domestic customers with different or additional information with the aim of promoting engagement in the domestic retail energy markets". The CMA's focus here was on information that a supplier should provide to its own customers about its own tariffs in the normal course of its business.
58. The CMA did not suggest that the supplier should be required to provide information about the tariffs of other suppliers. Indeed, the CMA had earlier indicated why it thought this would be undesirable. It rejected the suggestion that suppliers be required to inform their customers of the cheapest tariff in the market (across all suppliers) on two grounds.

> "140. … First, we were concerned that by forcing energy suppliers to share detailed pricing information, this remedy may weaken competition and encourage or facilitate some form of (tacit) coordination between suppliers. As a result, this remedy could have the opposite effect from that intended, resulting in increased prices for customers. 141. Second, we considered that requiring suppliers to advertise competitors' tariffs would not provide customers with the correct incentives to engage effectively in the market in the longer term, as they could rely on their supplier to conduct a search on their behalf and provide them with the results. This could encourage customers to remain relatively disengaged in the future, undermining our other remedies to facilitate widespread consumer engagement." (CMA, *Notice of Possible Remedies*, 7 July 2015)

59. In contrast, providing information about the tariffs of other suppliers is precisely what Ofgem has required a succession of participating suppliers to do in its various trials.
60. The CMA did recommend that Ofgem test aspects of the marketing communications by rival suppliers (e.g. form and frequency). But this was explicitly in the context of the database remedy (*Final Report* para 13.23). The recommendation was not in the context of the remedy requiring suppliers to provide appropriate information to their own customers.
61. The CMA did not endorse the concept of a collective switch. It did not discuss an opt-in switch but it explicitly rejected a remedy based on an opt-out collective switch, and its arguments to some extent apply to opt-in switches too. Thus, the CMA acknowledged that "143. … the competitive auctioning process should push down prices to the competitive level, realising the benefits of competition without requiring customer engagement", and that such a process would avoid certain problems associated with price regulation. But it had a major reservation.

> "144. However, we concluded that this remedy suffered from several important weaknesses in the context of the GB energy retail market, including: (a) The collective switching of large numbers of accounts at a single point in time could create significant confusion and disruption for customers. In particular, we were concerned that the number of erroneous transfers and delays in transferring customer accounts could increase significantly, resulting in material detriment; and (b) By specifying the type and quality of service to be offered to customers in advance, this type of scheme may limit innovation as energy suppliers are unable to test and refine different products with customers. Overall, we considered that these negative potential effects meant that this type of remedy would not be effective and proportionate." (CMA *Notice of Possible Remedies* 2015)

62. The CMA does not seem to have envisaged that its two remedies – the provision of information by a customer's own supplier and the provision of the disengaged customer database - should be combined. Yet it seems possible that this is what Ofgem envisages, at

least if it is to extend its trials to reach all the customers that the CMA considered to be disengaged.

63. Ofgem's approach to facilitated/bulk collective switching thus seems to be at variance with, or at least goes beyond, what the CMA recommended. This is not necessarily a concern for New Zealand, except insofar as it indicates that a collective switch is by no means a policy option on which GB competition and regulatory authorities deliberated and came to unanimous agreement. This policy option emerged despite, rather than because of, the CMA's recommendations.
64. Since the Energy Market Investigation, the CMA seems to have changed its mind and become more enthusiastic about collective switches.[18] Perhaps it now saw this as the only plausible remedy for the large customer detriment that it had identified
65. A question for New Zealand is therefore how to balance, in the context of the New Zealand market, the potential advantages of collective switching against the reservations that initially led the CMA Energy Market Investigation not to pursue it, viz, the possibilities of encouraging tacit collusion by suppliers, reducing customers' incentives to engage in the market, causing confusion and disruption for customers, and limiting innovation by suppliers.

What are the limits to regulatory involvement and collective switching?

66. Against the CMA's concerns just cited, it might be argued that Ofgem's opt-in trials have not created significant confusion and disruption for customers. But those trials that have so far been reported involved at most 50,000 customers. If 22.4% of those customers accepted the offered deal or another one, that is less than 12,000 customers changing supplier.
67. The Autumn trial involved 100,000 customers. There have been no reports of confusion and disruption associated with it, although the host supplier itself objected to the legality and scale of the trial, as noted below. At the previous switching rate, a trial of that size would mean up to 24,000 customers changing supplier.
68. In the second High Court case (see below), Ofgem referred to the possibility that "a collective switch be rolled out as a steady policy intervention". (para 50) The judgment says that "Ultimately, if there was customer switching and the data were sufficiently rigorous to have confidence in the results, Ofgem would then be able to scale up the intervention to millions of customers." (para 118) The CMA estimated that there were up to 10 million disengaged customers on SVTs that might go on to its proposed database. (CMA *Final Report* para 11.135)
69. How might this scaling up work? Deller et al (2017) have some discussion of such issues when using a database for collective switching. They note that, in the Big Switch exercise, winning supplier Cooperative Energy imposed a limit of 30,000 new customers. Hence they suggest "Assuming a block size of 25,000 households is reasonable, the initial stock of disengaged consumers would need to be split into 400 blocks." (p 31) They have some discussion of implementation issues, including whether to have frequent or infrequent auctions. Importantly, however, they assume a single offer put to these customers as a result of an auction: they do not provide for assistance by a consumer partner such as Energyhelpline, assisting with

[18] In the NPower legal challenge to Ofgem (see below), the December 2018 High Court judgment explains that the CMA argued that "where a potentially effective intervention has been identified (such as the collective switching that was the subject of the Scottish Power trial) then the testing of that intervention should progress expeditiously". (para 82) Also, "it is unwarranted and premature to draw the conclusion … that no useful steps towards implementing a collective switching measure such as that tested in the Scottish Power trial could take place now". (para 90).

switching and explaining other offers on the market. This seems to have been fairly integral to the latest Ofgem collective switch trials, insofar as alternatives to the negotiated collective switch accounted for half of all the stimulated switches.

70. Suppose, instead, that Ofgem were to proceed with a customer partner, but in increments of 100,000 customers as per its latest trial. That would require 100 collective switching exercises. Assuming each one takes about 3 months to run, that would be 4 exercises per year. At that rate, it would take 25 years to approach all 10 million disengaged customers.
71. Could the size of each exercise be increased? This is not obvious: evidence was given in the same High Court case that "it was clear that there was no capacity [on the part of consumer partner Energyhelpline] to deal with a trial of more than 100,000 customers at one time". (para 43) Suppose instead that, say, 5 consumer partners could be appointed to operate simultaneously. (There are 11 Ofgem-accredited price comparison websites, presumably some have to be left to cope with the usual flow of non-collective switching.) That would enable 20 exercises per year, making offers to (5 x 4 x 100,000 =) 2 million customers per year, and transferring approaching half a million of them to a new supplier. It would still take 5 years to get round to all 10 million disengaged customers, transferring perhaps 2 million of them in the process.
72. Does spreading the collective switching program over five years adequately address the concern identified by the CMA and Ofgem? It would mean that only one fifth of the identified disengaged customers were actively approached in the first year. No less than 2 million such customers would remain unapproached for over four years.
73. But once the 10 million (or fewer) disengaged customers have been offered a collective switch, is that the end of the programme? If 22.4% of them switch, what about the 77.6% of them that decline the switch? If the competitiveness of the market depends on most customers being engaged, is it acceptable simply to abandon over three quarters of the initially disengaged customers? Should they not be approached again? And if necessary again and again?
74. Moreover, the definition of a disengaged customer seems to be one that has not switched supplier in the previous three years. This means that each year a whole new cohort of customers is redefined as disengaged, and needs to be approached.
75. The implication seems to be that, once Ofgem has embarked on this path, it must continue to organise collective switches on a very large scale and on a continuing basis. At least, it must do so until there is evidence that customers have changed their nature and/or habits, and have taken to regularly engaging and switching supplier.
76. Is it realistic to think that Ofgem could manage such a large scale and continuing programme? There are reasons to question this. Ofgem has not so far managed to construct and make available the promised database, and is presently nearly a year beyond its own target of April 2018 for doing so. Reasons put to me (not by Ofgem) include objections and changing views on the part of the Information Commissioner's Office (ICO) as well as the management and resourcing of the project at Ofgem.
77. A question for both GB and New Zealand is whether there are reasons to believe that a programme of comparable size and complexity could be managed and achieved without disturbing the smooth running of the present market and switching process? Or would it be more prudent to target a smaller, more limited and therefore more manageable set of customers?
78. Taking the latter option, one priority might be disengaged customers that are vulnerable in some way, rather than customers that are able and affluent. Another priority might be customers that have not ever switched supplier rather than customers that have not switched in

the last three years. On that basis, would it be possible to reduce the GB target customer base from some 10 million to, say, one million? And if it is further assumed that the main aim is to assist vulnerable customers to find a potentially more suitable supplier rather than to change customer behaviour to make them more engaged, that would correspondingly limit the need to repeat the exercise ad infinitum. Although the CMA and Ofgem seem attracted by the latter aim, the EPR seems to have taken a more pragmatic approach that could accommodate the former aim.

Costs and benefits: the Cheaper Energy Together schemes

79. There has been considerable discussion about the benefits of different schemes for encouraging customer switching, but little or no discussion of the costs. One report about some early Government-supported collective switching schemes does contain brief reference to both benefits and costs, and therefore seems worth noting. [19] The schemes are described as follows.

> "Through Cheaper Energy Together, the Department of Energy and Climate Change [DECC] supported the development of innovative collective switching schemes for energy, where consumers group together to negotiate a better deal with their gas and electricity suppliers. … Through the funding we aimed to support a variety of different approaches to test what was effective in engaging with consumers, particularly those who have not switched before and vulnerable households. …. Over the short period that this fund was available between December 2012 and March 2013, schemes succeeded in engaging over 190,000 households with over 21,000 households switching energy suppliers and saving an average of £131 on their bills." (p 5)
>
> "Individual schemes are usually organised by Local Authorities, community and third sector organisations and are often facilitated by a third party who negotiate a tariff with energy suppliers on behalf of the consumers All schemes supported by Cheaper Energy Together were required to have a focus on engaging with vulnerable consumers. Schemes were also asked to propose innovative approaches to collective switching in order to establish an understanding of which approaches were the most successful. Money was awarded to 31 projects, which together covered 94 local councils and eight third sector organisations in Great Britain. Funding was available in the financial year 2012/2013 and was awarded in December 20121. Therefore schemes had a 3 month timescale over which to deliver their projects, which represented a significant challenge." (p 6)

80. There were many interesting findings. For example, the average conversion rate of customers who registered and provided their full details was 11% but the range was 5.5% to 23.1%. There was a higher incidence of switching among direct debit customers than among standard credit or Prepayment Meter customers. Local authorities and third sector organisations were able to use their local knowledge to effectively identify and engage with vulnerable consumers, but "this is resource intensive since it often involves face–to-face contact, it takes time to explain schemes fully and assist consumers in finding the right information they need to switch". (p 12) "Most schemes offered additional benefits to consumers through cash-back offers." (p 12) The larger auctions were won by the larger suppliers, the smaller ones by smaller suppliers.

[19] *Helping Customers Switch, Collective Switching and Beyond*, Department of Energy and Climate Change, 2013, p 5.

81. There was no formal cost-benefit analysis of these schemes, but it is worth noting the recorded cost of the policy. 21,641 customers are recorded as having switched supplier with expected financial savings averaging £131 per customer, yielding total savings of £2.7 million. DECC funding for this policy was £5 million. In other words, the cost to Government (taxpayers) was nearly twice the savings that these customers achieved.
82. Of course, there are many qualifications: the savings might have continued into later years, other costs might have been involved as well, this was an early experimental programme, the emphasis was on vulnerable customers, and so on. [20] The point here is simply that collective switching schemes have costs as well as benefits. They need to be assessed against other possible ways of engaging and protecting customers.
83. More generally, Amelia Fletcher gives a good recent account of "four overarching categories of engagement intervention", viz pure disclosure (of information), comparison tools (across different products), switching interventions (to enhance consumers' ability to act) and pure attention tools (to get consumers to engage).[21] The lessons she draws are 1) the importance of consumer testing via randomised control trials, 2) the importance of revisiting markets to carry out ex post evaluation of effectiveness, 3) don't blame customers for lack of engagement 4) engagement interventions are unlikely to be a panacea in all markets, given the costs and difficulties involved and the distributional consequences across consumers, 5) "there seems to be a consensus developing across UK regulators that interventions to change the choice architecture facing consumers can be more powerful in improving market outcomes than interventions involving disclosure"[22], and 6) regulators may face a difficult choice between imperfect engagement interventions and more interventionist measures such as price regulation which may weaken the incentive to engage.
84. For present purposes, the main lessons are that collective switching, as an engagement intervention, is unlikely to be a panacea; that it is important to estimate the costs and difficulties involved; and that it is important to estimate the distributional consequences across consumers, particularly via the impact on pricing by suppliers.

The need for trials

85. The EPR suggested that a bulk switching deal in New Zealand could be modelled on Ofgem's Collective Switch trial. This trial followed certain other smaller trials. However, it cannot be assumed that Ofgem has reached a situation where the "best" type of trial has now been identified and widely agreed upon, so that the Electricity Authority (for instance) could immediately proceed to negotiate such a deal.
86. This is not only because Ofgem's subsequent collective switch Autumn Trial is still in process and results have not yet been reported. There are many different potential design factors to consider, and their interactions are not yet fully understood. The results of any trial depend on a variety of considerations that vary from one supplier to another. For example, the Collective Switch trials have been with two large suppliers that have relatively low proportions of long-standing SVT customers: would the responses be the same for large suppliers with relatively

[20] For further discussion of this and other schemes, see also David Deller et al, *Collective Switching and possible uses of a disengaged customer database*, CCP and University of East Anglia, August 2017 (a report commissioned by Ofgem), pp 12-14.

[21] Amelia Fletcher, "Disclosure and other tools for enhancing consumer engagement and competition", CCP Working Paper 18-13, University of East Anglia, 2018.

[22] "Changing the choice architecture" seems to mean either forcing a choice (e.g. requiring customers to make an active choice of browser instead of automatically accepting Microsoft Internet Browser), or altering the default options (e.g. banning opt-out selling online in the EU).

high proportions of such customers, suppliers who might argue they have more loyal customers?

87. Are there differences in customer response as between different parts of GB, or in rural versus urban areas? Are there differences by payment method, or by income or other socio-economic characteristics? How far was the customer response influenced by the recent price increases?
88. Changing information during the course of the trial could have an effect, and the extent of this could well be hard to measure. For example, it seems that the initial estimated savings for the various tariffs in the latest (Autumn) collective switch trial were on the basis of tariffs obtaining before the SVT Tariff Cap was set, and before suppliers announced their future prices. The follow-up letter incorporated revised and lower estimated savings assuming that the Tariff Cap would come into place and with revised tariff data. So the final customer response may have been be higher than it would have been had the (lower) estimated post-Tariff Cap savings been used in the initial letter (because the higher projected savings got more customers interested). But by how much is a matter of conjecture.
89. Other consequences of a bulk collective switch are not easily assessed via trials. For example, what impact would it have on prices in the market generally? Many suppliers have looked to their standard variable tariffs to substantially cover their overhead costs while pricing their fixed tariffs to attract new customers. If the switch substantially reduces the number of customers on standard variable tariffs, or reduces the average time they spend on it, suppliers might look to increase those tariffs to cover overhead costs. Also, if low fixed-price tariffs are used to attract new customers, with the prospect of them staying for some years on a higher priced standard variable tariff, then a shorter prospective stay on the standard variable tariffs will make it less attractive for the supplier to offer low fixed price tariffs.[23]
90. Another consequence of large scale bulk collective switches is not easily measured by trials. The more that a regulatory authority intervenes in the market to influence the nature and extent and direction of switching, the more risk and cost this imposes on market participants. This would be reflected in average price levels, and could impact on the willingness to invest and innovate, and on the ability to implement new or established programmes (e.g. for social and environmental purposes).
91. Most importantly, of course, all Ofgem's evidence about the impact of trials relates to GB. How far this carries over to New Zealand remains to be discovered. This means that if the EPR decides to recommend a bulk switching scheme, then the Electricity Authority (or some other agency) will first need to carry out its own substantial programme of trials of the kinds of parameters that Ofgem trialled.
92. New Zealand could with advantage carry out trials more extensively in certain respects. For example, there is scope to relate switch rates to demographic characteristics, consumption levels, and amounts saved. Tracking the behaviour of switchers over time could shed light on whether the availability of collective switches deters customers from subsequent individual engagement because they can get the best tariff without effort, or whether such switches stimulate more individual switching because they demonstrate how easy switching is. This seems rather important: if collective switches tend to discourage customers from individual engagement, when if ever does regulatory involvement in collective switching cease?

[23] Thus, "enhancing engagement amongst the already engaged can have the effect of increasing the difference between the engagement levels of these two groups. As prices fall for the engaged, the unengaged may see less benefit, no benefit at all or may even see their prices rise". (Fletcher op cit, p 5) For these and other related issues, see also Deller et al (2017) s 5.

Concerns of suppliers

93. Valuable though trials can be, the concerns of those suppliers invited or required to carry them out should not be underestimated. On the one hand there are privacy laws, which would ordinarily preclude suppliers from making available many relevant customer details to other parties. The implications of such laws need to be explored, and perhaps refined. Where necessary assurance needs to be provided that participating suppliers are not breaking these privacy laws and thereby rendering themselves liable to prosecution.
94. On the other hand there are the commercial realities. Such trials are costly to put in place, in terms of information provision to the regulator and its agents, and communication with customers. They are also a commercial threat: the suppliers carrying them out are being asked to cooperate in facilitating the transfer of their customers to rival suppliers. In the Ofgem collective trial cited by the EPR, over one fifth of the customers left the participating supplier. In the High Court action preceding the Autumn Collective Choice Trial with 100,000 customers, it was estimated that NPower's loss of revenue would be about £30 million. At that rate, application of the process to all 10 million customers that the CMA referred to means that the six large suppliers might be expected to facilitate the loss of over two million of their long-standing customers with an aggregate loss of revenue of some £3 billion.
95. Not surprisingly, suppliers have expressed concerns about possible violation of the privacy laws in the UK and also about the size and nature of some of the trials. See for example NPower's legal challenge to Ofgem as summarised in the next section. Any programme of collective choice trials will therefore require careful consideration of the legal position, with respect to both privacy laws and obligations of suppliers. Even more is this the case with respect to the eventual implementation of a full collective choice process itself.

NPower's legal challenge to Ofgem

96. The information about NPower's challenge that has been available on Ofgem's website has been limited, but two High Court judgements now give a fuller picture. Briefly, in terms of the formal steps taken by the parties, on 31 August 2018, Ofgem issued a Direction requiring NPower to participate in a consumer engagement trial known as the Active Choice Collective Switch Autumn Trial. On 14 September 2018 NPower informed the Authority that it did not intend to comply with certain aspects of the Direction and on 20 September 2018 failed to send particular communications to a number of its customers. On 24 September Ofgem issued a Provisional Order requiring NPower to comply. On 2 October NPower applied to the High Court to quash the Provisional Order. Ofgem applied to enforce it. On 5 October the High Court gave its judgment. [24]
97. What were the issues here? On 12 July 2018 Ofgem informed NPower that two suppliers would be chosen from those suppliers with more than 500,000 customers on a standard variable tariff (that is, essentially the Big Six Large suppliers). Each supplier would identify 100,000 eligible customers. NPower initially argued that it should not be chosen because it had volunteered for an earlier trial and was also to be involved in the disengaged customer database. NPower later accepted that it was fair that it was selected, but it was also concerned about the customer numbers. It considered that 100,000 customers should be viewed as more than a trial and expressed concern that it would suffer a significant financial detriment. It suggested a trial of 10,000 to 30,000 customers.

[24] https://www.ofgem.gov.uk/system/files/docs/2018/10/gema051018app_NPower_judgement.pdf

98. Ofgem explained "To take this option to the next level, we need to understand whether such a service is scalable. To do this we need to understand two things: (1) can call centres deal with the increase in the volume of the customers they will need to interact with; (2) what is the market appetite for bidders on the collective switch auction at larger volumes. Taking that all into consideration, we came to the conclusion that we need to ramp up the numbers to circa 200,000 customers. To limit the impact on the chosen supplier, we took the decision to split that between the two suppliers." (para 6)
99. On 14 September NPower indicated it was not comfortable with 100,000 customers: half that number would be acceptable but it was not willing to proceed with the larger number. Its reasons included that the direction could not be ordered under Standard Licence Condition SLC 32A, that Ofgem had not followed its own guidance, that Ofgem had not considered proportionality at all, in breach of public law, and that Article 1 of the first protocol to the Human Rights Act was engaged.[25]
100. The High Court judgement acknowledged that, "if NPower is required to comply with the Provisional Order then it is a practical certainty that it will suffer some loss, and potentially a significant loss. If the number of customers that choose to switch to an alternative supplier follows the trend in the Scottish Power trial then this is likely to be in the region of £30 million." (Para 20) But the High Court held that some loss was inherent in the concept of a trial.
101. Ofgem's governing body GEMA argued that the matter was urgent. "First, a market-wide cap is due to be introduced in January 2019, but on a temporary basis. While the cap is in place the nature of the market will be fundamentally different so the comparison with a Scottish Power trial would be impossible. GEMA needs to complete this trial before the introduction of the cap so that it has the evidence necessary to make decisions as to whether it should introduce market-wide customer switching provisions as an alternative to the cap in the future. Secondly, the timing of the trial is now at the very end of the possible window, because customer behaviour in the period immediately before Christmas changes (as it was put, switch rates fall in December) so that, again, a like-for-like comparison with the Scottish Power trial is damaged." (Para 28) NPower disputed the urgency and commented that the introduction of the cap as a reason for the trial taking place this autumn was only revealed to them in evidence served in this case. (Para 29) The High Court accepted that the matter was urgent.
102. The Judge commented that " I did canvass in the hearing the possibility that the fact that the cap is about to be introduced is, even now, something which means this trial would be distorted so as not to be a comparable trial with the Scottish Power trial. However, that is something that I am only in the position to speculate about, there being no evidence at all to that effect. It would be wrong for me to rely on such speculation over the considered views of Ofgem as to the worth of the trial that it has put in place." (para 37)
103. On 5 October the High Court issued a judgement requiring NPower to comply with the Order. But that was not the end of the matter. After further legal processes, on 31 October NPower applied for a judicial review to challenge the lawfulness of Ofgem's initial Direction. The High Court judgement on 21 December 2018 throws further light on the issues and arguments.[26]

[25] "Article 1 Protection of property. Every natural or legal person is entitled to the peaceful enjoyment of his possessions. No one shall be deprived of his possessions except in the public interest and subject to the conditions provided for by law and by the general principles of international law."

[26] https://www.ofgem.gov.uk/system/files/docs/2018/12/NPower_v_gema_judgment_dated_21_december_2018.pdf

104. For example, NPower argued that "The only explanation for Ofgem continuing with the NPower trial in these circumstances is that it is doing so solely or materially for the purpose not of testing anything (more specifically, replicability) but rather to obtain a result: consumer switching. This is clearly beyond the scope of SLC32A – it [presumably SLC 32A] is a measure to trial consumer engagement measures to inform future policy interventions, it [is] not a regulatory tool to achieve a (direct) result." (para 42)

105. NPower also argued that "insofar as the rationale of Ofgem was commercial appetite for suppliers taking on large volumes on Commercial Switches, this fell outside the scope of the scope of the Energy Market Investigation". (para 54)

106. The High Court was not convinced. On 21 December it dismissed NPower's application to quash the Provisional Order and also dismissed the application for judicial review.

107. Nevertheless, similar concerns can be expected to surface in the industry if Ofgem were to decide to "take this option to the next level".

Is switching all about price?

108. The CMA assumption, broadly adopted by Ofgem, is that electricity is a homogeneous commodity and suppliers are essentially identical. On this basis, the level of tariff should be by far the main consideration for customers. The CMA argued that customers do not recognise this: they are not sufficiently engaged and hence need to be prompted to engage more regularly and more intensively. This is both for their own sake - to avoid passing up good opportunities to pay less for energy - and for the sake of others, because effective competition requires engaged customers to keep suppliers on their toes and stop them increasing prices.

109. In practice, the way of measuring and demonstrating this engagement is by the rate at which customers switch suppliers. Hence, lack of switching is a concern, and increase in switching is a measure of success. So, for example, Ofgem says that "The simplified collective switch trial … is the most successful trial Ofgem has completed to date" and "the most successful arm of the trial increased switching rates to 10 times the control group".

110. However, the underlying assumptions here – the view that electricity or energy is a homogeneous product, that customers are or should be primarily driven by price, and that lack of switching and money apparently left on the table indicate lack of engagement, and that the aim should be to increase switching - are increasingly subject to challenge.

111. Deller et al (2017) provide a good review of (mainly) the empirical literature on customer switching.[27] Their paper analyses decisions made by customers in The Big Switch organised by Which? in 2012, at that time the largest collective energy switching exercise conducted in the UK.

112. They find that "a range of non-price factors … are all associated with the switching decision", and that "most of the factors are consistent with consumers making a largely rational decision when choosing not to switch, even if this results in monetary savings being left on the table". Their survey respondent model "manages to predict, overall, more than 80% of the observed [Big Switch] decisions, suggesting that a rational model of consumer behaviour can go quite a long way to explaining why financial rewards alone may fail to induce switching".

113. They conclude that (1) "switching cannot be relied on to put all consumers on the cheapest deal for them"; (2) "consumers do not regard energy as a homogeneous product … [so] forcing consumers to switch to a particular supplier may reduce utility for at least some consumers";

[27] David Deller et al, "Switching energy suppliers: It's not all about the money", Working Paper 17-5. Centre for Competition Policy, University of East Anglia, 2017

(3) "opt-in collective switching processes …do not deliver a panacea in getting a wide variety of consumers to switch to cheap energy deals"; and (4) "policymakers should lower their expectations about the power of consumer engagement to promote competition".

Are customers choosing tariffs or suppliers? And what about customer loyalty?

114. Broadly consistent with this alternative view is the perception that many customers don't really want to spend time and mental effort engaging in the energy market and are therefore more concerned about the reliability and long-term price level of their supplier than the CMA allowed. Whereas the CMA considered that customers were choosing and changing tariffs, most customers think they are choosing and changing suppliers. Hence for these customers, a key question is whether a new supplier with a lower price today will be better or worse over time than their present supplier, with respect to future price, quality of service, and so on. So even though customers can see the alternative of a lower priced tariff today, can they trust the new and possibly unknown supplier when it comes to the future?
115. Consistent with this, there is evidence from Ofgem's trials and elsewhere that many customers prefer to switch to an established supplier that they recognise.[28]
116. The potential risks associated with low-price but unknown suppliers have become a particularly relevant concern in the UK. They may potentially be relevant in New Zealand. There were over 70 suppliers in the UK last year, most of them completely unknown to most customers and too small to be liable for the social and environmental costs borne by larger suppliers. Some suppliers increased their prices considerably or repeatedly. Some suppliers moved new customers on to much higher standard variable tariffs once their initial low priced fixed tariffs expired.[29] Some suppliers raised their Direct Debit levels significantly, some suddenly introduced higher direct debit levels in winter when consumption was higher. Some suppliers were inundated by complaints, and some were unable to cope with the volume of customers wanting to contact them by phone or online. In some serious cases Ofgem has stepped in to prevent suppliers from taking on new customers until they improve their customer service records. About a dozen of the new and small suppliers have gone bust over the last year, in default to their customers (albeit these customers were bailed out by other customers via Ofgem's procedures).
117. Customers are plausibly concerned about such risks and are therefore more prudent than the CMA allowed. If there are risks, it may well be sensible for a customer not to switch immediately to the supplier that offers the lowest price at one moment in time, but rather to wait and gather more information. And whereas the CMA notes that certain sets of vulnerable customers are less than averagely engaged in the market, this too may be prudent insofar as such customers may be less able to deal with the possible adverse consequences of moving to

[28] With respect to Ofgem's Cheaper Market Offers Trial, "81. Ofgem noted that while only 7% of the tariffs on the letters were from the SLEFs [Six Large Energy Suppliers], the SLEFs gained 38% of switchers in the trial. This suggests that SLEFs received a disproportionately high number of switchers given their prices, and may indicate some preference for the SLEFs among customers. However, we note that SLEFs receiving 38% of switchers is broadly consistent with the more general evidence we have received on customer switching patterns (see Appendix H). 82. Ofgem noted that having an offer from a SLEF on the letter was not correlated with customers' propensity to switch, although it noted that some customers value switching to a brand they recognise. It noted that a lack of brand awareness was a barrier to switching to small suppliers for some customers." CMA, *SSE Retail and nPower, a report on the anticipated merger*, 10 October 2018, Appendix B *Customer Engagement*, paras 81-82.

[29] My previous paper submitted to the EPR (see above) gives some examples, many others could be cited.

an unknown supplier. Other customers, with higher incomes and educational levels and owning their own properties, may be better placed to take the risks of exploring unknown suppliers offering lower prices.

118. There is another important question. If customers are approached and encouraged by Ofgem to switch after three years with the same supplier, how does this square with the concept of customer loyalty? What is the point of a supplier trying to provide a consistently attractive product at a consistently good value price, if a regulatory-led policy is going to repeatedly require the supplier to invite and indeed encourage the customer to move to another supplier?
119. The CMA may not have attached much value to customer loyalty. It may have considered that customers of the former incumbent suppliers were simply disengaged rather than loyal. But is there no role at all for customer loyalty in the retail energy market?

Do switching customers get better suppliers – and which are they?

120. It was suggested earlier that the main aim of policy might be to find a better supplier for vulnerable customers rather than to make all customers more engaged in the market. Is there a supplier that they may prefer for reasons of price and/or service? Hitherto Ofgem seems to have taken the first approach whereas the EPR seems to have taken a relatively pragmatic view that would allow the latter approach.
121. If the latter approach is taken, then how in practice to identify better suppliers, that will not simply provide a lower price at the point of switching but that will also satisfy customers better over a period of time? Hitherto, Ofgem or its agents have been identifying customers and inviting and encouraging them to participate in collective switches. Have they been able, or are they able in future, to ensure that these customers end up with a supplier that not only offers a lower price today, but also is a supplier that the customers themselves continue to regard as better than their previous supplier?
122. To date, the main criterion in the Ofgem trials has been price. For example, in the Cheaper Market Offers Letter (CMOL) trial, tariffs had to be selected on the basis of lowest price (measured against customer's consumption in the last year), agnostic of supplier or tariff type.
123. But there are many different kinds of tariff on offer in the market – fixed for one year, eighteen months, two or three years, or of course variable. (Not to mention tariffs that track wholesale prices or offer opportunities to purchase packs of energy at discounted prices.) In the above CMOL trial in summer 2017, there were around 30 different tariffs on the various letters, 9 of which tariffs were variable and 21 were fixed.
124. Then there is quality of service. In the UK there are various measures of customer service (e.g. provided by Citizens Advice, Which?, Trustpilot and by the various Price Comparison Websites). They all differ to some degree. I have elsewhere proposed using an Overall Customer Service score that is an average of the first three of these measures.[30] Of course, what is considered as important or as good service may differ from one customer to another. And supplier prices and reputations can change over time, quite rapidly in some cases.
125. It is therefore not simply a question of picking the lowest bidder for a homogenous product. Someone, either the regulator or its agent appointed to implement a Collective Switch approach, is put in the position of (directly or indirectly) deciding what type and level of tariff customers should be offered and with what quality of supplier. The process thereby necessarily favours some suppliers relative to others.

[30] Stephen Littlechild, "Savings available in the retail energy market and the Overall Customer Service score, University of Cambridge Energy Policy Research Group, at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2019/02/S.-Littlechild_12-Feb-2019.pdf

126. Has there been any attempt in the Ofgem trials to ensure that the customers invited to switch did not land up with unsatisfactory suppliers? Or were they invited to switch to suppliers that were perhaps not competent or that later increased their prices or had high standard variable prices relative to their low fixed price tariffs, or were not likely to go out of business, or had good rather than poor customer service records?

127. On the basis of published information, the initial CMOL Trial and the Check Your Energy Deal are not said to have put particular obligations on the two participant companies to ensure that the offers placed before customers were from "better" suppliers as opposed to lower priced suppliers. This is not to say that no steps were taken: In the CMOL Trial, offers had to be from suppliers that had completed Controlled Market Entry.[31] But this is pretty minimal. Non-price considerations do not seem to have been identified as relevant or appropriate.

128. The Collective Switch trial reflected more awareness of customer service issues. "When selecting the collective switch tariff, Ofgem required Energyhelpline to choose a supplier that had a customer service rating of a least three out of five stars (according to Energyhelpline's ranking system)." In addition, "Energyhelpline also provided customer service ratings. This is important as customers should compare suppliers on their customer service performance as well as on the price of tariffs".

129. The above are all considerations to take into account ex ante, when a customer is deciding whether to switch and to which other supplier. What about ex post evidence on how well customers were satisfied with their new supplier?

130. None of the trials to date has provided any evidence of actual achieved savings as opposed to projected savings, nor of relative tariff levels after, say, one year, nor of customer opinions on customer service and other matters. I understand that some form of ex post assessment may be in process for some of these trials, but no information is available at present.

131. In at least one case non-price considerations subsequently surfaced as significant. Extra Energy was a supplier launched in the UK in 2014. It was then said to offer the best buy in the market and was soon reported to be taking over one third of all customers who switched energy supplier. In February 2016 it was chosen by the Sun newspaper as its Partner Provider for its People Power deal, said to save customers switching from a Big Six supplier an average of £358. But also in first quarter 2016 it reached what Citizens Advice said was "the highest complaints ratio ever recorded" in the five years of compiling complaints data league tables. Following concerns raised by Citizens Advice and The Ombudsman, in July 2016 Ofgem opened an investigation into whether Extra Energy broke rules relating to billing, customer service and complaint handling.

132. In May 2017, with these questions as yet unanswered, Extra Energy's tariff was one of three offered to customers in one of the letters sent to participants in one of the CMOL trials. Presumably some customers switched to it. In November 2018 Extra Energy ceased trading (with over 100,000 customers). Ofgem revoked Extra Energy's licence and closed its own investigation, which had not then been completed, while indicating the extent of its previous concerns.[32]

[31]Controlled Market Entry is a probationary period during which the energy supplier must prove (to the industry body Gemserve) that it has in place the appropriate systems and processes to deal with the complexities of the market and that it is able to operate without disruption to other market participants.

[32] "We were investigating whether Extra [Energy] breached numerous licence conditions and Consumer Complaints Handling Standards relating to treating customers fairly, frequency of billing, timely provision of final bills, provision of annual statements, return of credit balances, handling meter readings appropriately, transfer blocking, and complaints and call handling." (Ofgem website)

133. If collective switch trials are the forerunner of a policy to influence the actions of a significant proportion of customers (up to 10 million disengaged customers in GB) and in turn to influence the pricing policies of competitive suppliers generally (to reduce tariff differentials), and if this might be a policy continuing over time, as long as not enough customers are sufficiently engaged in the market, then the possibility that the regulatory authority might be inviting or encouraging customers to switch to inappropriate suppliers becomes a more serious matter.

Concluding thoughts

134. This paper has sought to describe and explain Ofgem's present policy of regulatory-led collective (or bulk) switching, and to note some concerns and implications associated with it. The latest trial for which results are available suggests a significant (over 20%) response by disengaged customers to the collective tariff offered, and an average annual saving of £261 via that tariff. This was just after a widespread increase in tariffs, so customers were particularly sensitive (and arguably incensed!) at the time. Nonetheless, this seems to suggest that regulatory-facilitated collective switching could make significant savings for disengaged customers. It could also familiarise them with the process of changing supplier, even if it did not persuade them to become more engaged over the longer term.

135. There are, however, some reservations. First, the policy has been driven by Ofgem in response to the CMA's analysis and remedies. Even setting aside my own concerns about the validity of the CMA's analysis, there is a question whether energy markets in other jurisdictions are characterised by the same degree of problem as the CMA identified in the UK. The EPR seems to think this is not the case in New Zealand.

136. Second, the CMA was concerned that requiring suppliers to advertise competitors' tariffs could encourage customers to remain disengaged in future. Moreover, collective switching of large numbers of accounts could cause confusion and disruption for customers and could limit innovation by suppliers.

137. Third, there seem to be practical limits to collective switching. Is it actually feasible to offer collective switching to all the customers for whom this might be recommended? The burdens on regulatory agencies and on suppliers need to be considered. (To date, Ofgem's Disengaged Customer Database is not yet operational.) Also important is whether this is a one-off project or a continuing exercise. If it starts, when does it stop?

138. Fourth, the costs and benefits of such a policy need consideration. In the UK, the Cheaper Together policy of encouraging collective switching schemes cost nearly twice as much as the benefits secured from switching. More generally, collective switching schemes are unlikely to be a panacea.

139. Fifth, it is important to engage in trials before committing to a policy of collective switching. There is now some evidence from GB but how far this carries over to New Zealand remains to be discovered. And there are several respects in which GB evidence is lacking – for example, whether collective switching encourages or discourages subsequent individual switching.

140. Sixth, suppliers have legitimate concerns about collective switching. There are obvious concerns about violation of data privacy laws. Also, trials are costly, and require suppliers to invite their customers to leave. The latest (Autumn 2018) trial was estimated to cost the supplier £30 million in lost revenues. There has been one legal challenge to the trials, and other challenges to the implementation of policy cannot be ruled out.

141. Seventh, it might be assumed that energy and the suppliers are homogenous, so that switching is only about price. In the economics literature there are increasing challenges to this view. An

analysis of the Big Switch in GB concludes that consumers do not regard energy as a homogenous product and that opt-in collective switching processes do not deliver a panacea.

142. Eighth, customers think they are choosing suppliers, not tariffs. Given the very different reputations of suppliers, customers may be more prudent than the CMA realised. Reputation and customer loyalty are important. A regulator facilitating the transfer of customers to another supplier would need to consider, in addition, the quality of service, reputation, and likely future prices that would be charged by this supplier.

143. Ninth, if customers value service and good performance over time, how is this best identified? There is limited evidence in the GB trials to date that this was a consideration in proposing alternative suppliers. In one case a proposed supplier had the highest complaints ratio ever recorded, and went out of business some 18 months after being put forward in an Ofgem trial.

144. Tenth, the impact on the market needs to be considered. For example, such a large scale transfer of a particular type of customers would likely have an impact on prices in the market. For some suppliers, fewer customers on standard variable tariffs could increase the level of those tariffs necessary to cover total costs, and a shorter duration of stay could reduce the viability of offering lower prices to attract new customers. How to reconcile facilitating large-scale collective switches for disengaged customers with encouraging customer loyalty to high quality and trusted suppliers? Bulk collective switches could favour suppliers able to absorb large quantities of customers at the expense of smaller or newer suppliers that are not able.

145. In sum, regulatory-facilitated bulk switching may sound attractive at first. And it can help some customers to find a preferred supplier. But is it a one-off remedy or a policy that never ends? There are some potentially important legal, organisational and economic issues that need further consideration if it is to be successfully implemented, both in GB and in New Zealand.

Annex 1
Extract from Electricity Price Review, *Options Paper*, 18 February 2019, pp 16-17)

C6: Help non-switching consumers find better deals

The Electricity Authority or a contracted agent would negotiate a bulk deal for consumers who had not switched retailers for many years. Consumers could evaluate the savings of such a deal and opt out if they didn't want to switch. The Authority would need the power to require retailers to hand over information about long-term customers.

In New Zealand, between 400,000 and 750,000 households have never switched retailers since 2002 (when records began).(86) Some would have shopped around but not gone any further, or would have started to switch but accepted a win-back offer.(87) The high numbers strongly suggest many have never shopped around, despite efforts to simplify the switching process and campaigns to help consumers seek out better prices.

Such a scheme could be modelled on a recent trial in Britain – a suggestion raised by distributor Vector.(88) In early 2018, 50,000 British consumers took part in the pilot project, all of whom had not switched retailer for at least three years.(89) The British electricity regulator contracted a "consumer partner" to negotiate a bulk deal on behalf of the group, and to provide advice on alternative offers and savings by phone, email and internet.(90) In the trial, 22.4 per cent of consumers have switched, more than eight times the rate of a control group. These consumers saved an average of £298.(91) Almost a quarter of those who switched were over 75.(92) Only 0.1 per cent opted out of the trial, demonstrating that very few consumers are not interested in better power prices. Encouraged by these results, the regulator launched two larger trials in late 2018.

Based on the success of the British trial, we consider a similar scheme would help the same consumers here to get better deals.

We favour this option.

86 This is equivalent to between 23 per cent and 42 per cent of all residential consumers. First report, pg36.
87 Some of these consumers will also have benefited from a retention offer without switching retailer. First report, pg36.
88 Axiom Economics report, pp30-31, attached to Vector submission.
89 Consumers could switch to the collectively negotiated offer, or other competitive offers. See Ofgem's *Active Choice Collective Switch*, February 2018.
90 These included the collective switch tariffs and other offers in the market.
91 The report by the regulator Ofgem does not specify over what period the saving was made, or what percentage of a typical bill
it represented. But regardless, it is a not an insubstantial amount.
92 See Ofgem's *Active Choice Collective Switch Headline Results*, August 2018.

Annex Two

Extract from Active Choice Collective Switch Trial: Early Findings, Ofgem 20 August 2018

Collective Switch Trial Design

This Collective Switch was designed for customers who find it difficult or do not feel confident enough to navigate the complex range of tariffs available in the open market. It was designed to give a 'helping hand' and provide them with an exclusive tariff negotiated for them by an Ofgem appointed independent price comparison service, Energyhelpline. Ofgem also required Energyhelpline to consider customer service when selecting the winning collective switch tariff to offer customers. Around 50,000 disengaged customers were randomly selected to be in the trial.

Unlike other switches, customers did not need to enter their existing tariff details in order to have their personal savings from switching calculated. If a customer did not exercise their right to 'opt-out', they received letters showing how much they could save by moving to the collective switch tariff. Customers who contacted Energyhelpline online or by phone also received information about potential savings from deals across the market. They could then make an informed choice about whether or not to start a switch.

Trial Findings

Early findings indicate that the trial had a clear and substantial impact. Key points include:

- 22.4% of trial participants switched their energy deal;
- Almost a quarter of those who chose to switch via Energyhelpline were over 75 years of age;
- Phone switching was more popular than online; 71% of switches via Energyhelpline happened on the phone;
- Customers saved an average of around £300 a year ; and
- Total savings made by customers were approximately £3.3 million.

Switching rates

This is the highest switching rate achieved in our consumer engagement trials to date. This outcome is particularly impressive given that this group were amongst the most disengaged of energy consumers. On average, customers had been on a Standard Variable Tariff for six and a half years. The overall switching rate was over eight times higher than the switching rate of the trial control group of 2.6%.

The indications are that vulnerable customers also responded strongly. Customers on the Priority Services Register were almost as likely to switch their energy deal as anyone else, at 21.1%. Of the switches made through Energyhelpline, 24% were by participants over 75 years of age, with the oldest switcher aged over 100.

Customers switched to a range of tariffs through various routes. Approximately half of the switchers chose the collective switch tariff with another 40% moving to cheaper deals in the open market. Approximately 10% of this group chose another tariff with their existing provider.

Average savings

Customers saved an average of around £300 a year. The largest savings in the trial were made by participants who undertook an open market tariff search through Energyhelpline, saving £352 a year. On average customers who switched to the Collective Switch tariff saved £261 a year.

Trial features

We believe a number of key features led to these encouraging results:

• The trial offered customers a choice of routes to switch: giving customers the option to discuss their options with a person is likely to have helped with customer confidence about switching. The phone also provides a route to engage for the sizable group of disengaged customers who are not online, or only go online occasionally.

• Being able to switch via an intermediary rather than having to deal with suppliers directly was viewed positively. The lack of confidence that many disengaged consumers express about comparing and switching suggested that they might be more comfortable speaking to an intermediary, especially if they had queries or concerns. Switching levels were considerably higher than in previous trials where customers were advised to contact the supplier directly. Energyhelpline also provided customer service ratings. This is important as customers should compare suppliers on their customer service performance as well as on the price of tariffs.

• The trial was designed to take the hassle out of switching for disengaged customers. Customers received accurate savings calculations based on their own consumption information. Not only were they presented with an alternative tariff from a recognised energy provider, but the results show that it empowered consumers to investigate other options in the market.

• We gave customers the option to exercise their right to 'opt out' of participating in the trial and these were low at 0.1% of the eligible trial population.

Market making Obligations in New Zealand

Dr. Tom Hird

April 2019

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1 Introduction

1. Meridian Energy has sought consulting advice regarding a proposal in the independent Electricity Price Review options paper to implement mandatory market making obligations for wholesale electricity futures products on vertically integrated retailers.

1.1 Report structure

2. The remainder of this report is set out as follows:

- Section 2 provides a critique of the proposal to introduce market making obligations. In doing so, section 2 draws on the analysis in sections 3 and 4;
- Section 3 provides a literature review and empirical analysis of the relationship between bid-ask spreads and market uncertainty/volatility; and
- Section 4 provides a summary of UK experience with mandatory market making obligations plus a comparison of volatility in the UK versus New Zealand wholesale electricity markets.

1.2 Report author

3. I am Tom Hird and I am the author of this report. I have a Ph.D. in Economics and 25 years working as a professional economist for the Australian Commonwealth Treasury and in private industry. I have been assisted in my research by Johnathan Wongsosaputro and Dr Ker Zhang. However, the views expressed in this report are mine alone.

4. I have made all the inquiries that I believe are desirable and appropriate and no matters of significance that I regard as relevant have, to my knowledge, been omitted from consideration in this report.

Dr. Tom Hird

2 Critique of proposed mandatory market making obligations

2.1 Summary of options paper positions

5. The independent Electricity Price Review has released an options paper which, amongst other things, proposes the introduction of a mandatory market making obligation on the largest vertically integrated generator-retailer businesses in New Zealand.

2.1.1 Mandatory obligations are expected to improve efficiency

6. The options paper proceeds on the basis that, absent such obligations, there will be an inefficient level of liquidity in the market for hedging contracts. The basis for such a conclusion is not explained in detail but appears to be best described in the below quote:

> *Arrangements since 2010 have supported strong growth in the volume of fixed-price contracts traded and improved retailing competition.[108] However, the wholesale contract market has recently become increasingly fragile. For long periods in 2017 and 2018, buy and sell price spreads far exceeded the agreed 5 per cent limit – sometimes reaching more than 50 per cent. At the time, hydro storage levels were low and/or gas supplies were short, creating spikes in electricity spot prices. The spikes prompted at least one of the four generator-retailers to withdraw from market-making, citing "portfolio stress". The others quickly followed. This rapidly led to significant price spreads and muffled price signals.[109] Mercury, one of the four market-makers, said in its submission "the current voluntary market-making arrangements are not sustainable".[110]*
>
> > *[109] Wholesale contract price spreads are a key measure of market efficiency. When spreads are tight, wholesale buyers and sellers receive clearer electricity price signals – rather than having to judge whether the true value is closer to the buy or the sell price. Tighter spreads also make it easier for retailers to use contracts to manage their risks, such as adjusting their contract book to reflect growth in retail customer numbers.*

7. In this passage, and especially in footnote 109, the options paper appears to express the view that high levels of spreads are associated with market inefficiency.

2.1.2 Externality benefit from achieving lower bid-ask spreads

8. The options paper appears to acknowledge that spreads can rise because the costs and risks of being a market maker can rise – especially in volatile markets.

However, this does not prevent the options paper from proposing the imposition of market making obligations at regulated maximum bid-ask spreads.

> *Some submitters argued wider price spreads were acceptable during increased uncertainty about supply. We acknowledge this view has merit, and market-makers should not be required to assume undue risks. However, individual market-makers currently decide whether to take part in this activity. Nothing is made public about the criteria they use to arrive at decisions, or even whether they have withdrawn from market-making. Once one withdraws, the likelihood is others will follow. This arrangement renders market-making fragile and unpredictable.*
>
> …
>
> *Mandatory market-making happens in Britain and is being introduced in parts of Australia. Its introduction here would reduce the fragility of the wholesale contract market.*
>
> *A mandatory market-making obligation could be introduced relatively quickly. New regulation would also include provisions to temporarily relax the market-making obligations when certain conditions were met. In Britain, the obligation to quote fixed contracts can be suspended if the contract price moves more than a predefined amount on a single day. Adoption of a mandatory approach with predefined "stress" provisions would improve market resilience while avoiding undue risks and costs for market makers.*

9. While 'stress' provisions are envisaged such that a single bid-ask spread would not be imposed in all circumstances, the options paper must still envision that the regulated bid-ask spread would be binding in some circumstances. That is, it must be expected that the obligation will force market makers to provide the service at a lower price than they would voluntarily do so – at least in some circumstances.

10. The options paper does not clearly explain why this would improve market efficiency. However, it appears that the rationale is that the overall level of 'market efficiency' would be improved by regulating spreads to be lower than cost – presumably on the basis of an externality that flows from having predictable access to hedging instruments with low bid-ask spreads. This interpretation is consistent with the focus on reducing "*the fragility of the wholesale contract market*".

11. This interpretation is also consistent with the indication that mandatory obligations would only be temporary and would be replaced "*by an incentive-based scheme whereby companies best placed to act as market makers could be paid to take on that responsibility*". In this passage, the options paper appear to envisage a scenario where obligations were voluntarily entered into rather than imposed on market makers.

2.1.3 Vertically integrated suppliers are presumed to have to bear the costs of the obligations

12. The options paper presumes that the burden of the market making obligations should fall on vertically integrated generator/retailer operators.

> *The level of obligation on market makers could be* ***graduated based on a generator-retailer's size and extent of vertical integration****. Compliance monitoring and enforcement penalties would also be included.*
>
> *A mandatory market-making obligation could be replaced later by an incentive-based scheme whereby companies best placed to act as market makers could be paid to take on that responsibility.* ***A levy on vertically integrated companies above a minimum size could help recover market-maker fees****.*

13. That is, the costs of imposing the obligations would fall on vertically integrated suppliers – first in the form of an involuntary obligation only on them and, later, in the form of levy on them to fund a voluntary obligation regime.

2.2 Critique

14. This section critiques aspects of the option paper discussion and makes suggestions for subsequent analysis and policy. This critique relies on facts and analysis presented in detail in subsequent sections but which are summarised in this section.

2.2.1 Involuntary obligations involve real costs

15. A regime that forces some parties to offer to trade, and actually trade, at prices that they otherwise would not be prepared to trade imposes costs on those parties. These costs can be significant. As will be discussed in section 4.1, Ofgem's December 2017 consultation notes that: [1]

> ***When prices move significantly and rapidly, market makers often have their bids or offers aggressed and then pay a premium to reverse those positions once prices have moved in an unfavourable direction.*** *We were also told that this effect can be most pronounced at the start of market making windows where the narrow bid-offer spreads make price discovery difficult and prices can move very quickly.*

---

[1] Ofgem, Secure and Promote review: Consultation on changes to the special licence condition, December 2017.

16. This is consistent with the literature summarised in section 3.1 on market making which notes that the costs to market makers come from any mispricing by the market maker being exploited by informed market participants (attracting large volumes of trades at one or the other end of the bid-ask spread). The risk of this occurring is higher the higher is the uncertainty around the true market expectations of the fair price.

17. This variation in risk is managed by a variation in the level of bid-ask spreads – with higher bid-ask spreads in periods of high uncertainty/volatility. That is, cost reflective bid-ask spreads will vary with the level of market uncertainty/volatility. However, a regulatory cap on the level of bid-ask spreads will, should it be binding, blunt this price signal and lead to the price of market making being set below the cost and an expectation of losses by the market makers.

18. Ofgem noted that, due to high volatility in 2016, market making costs were around 10 times the levels observed in other years (market makers incurred costs of between 3 million and 8 million GBP in 2016) and much higher than Ofgem had expected when it introduced the regime. S&P Platts reports estimates of costs of between GBP 2 million and GBP 10 million for the six market makers in 2016.[2]

2.2.2 Costs in New Zealand can be expected to be higher than in the UK due to higher volatility

19. Sections 3.2 surveys the empirical literature and section and 3.3 provides supporting CEG analysis, both of which clearly demonstrate a strong link between high volatility/uncertainty and high costs of being a market maker. This, in turn, links high levels of volatility with high observed bid-ask spreads.

20. In light of this literature, section 4.2 compares the level of volatility in UK and NZ spot and futures energy markets. This analysis strongly suggests higher volatility in New Zealand (consistent with a greater reliance in the UK on more nuclear base load and more reliable gas supplies compared to New Zealand's greater reliance on more variable hydroelectric generation). This difference in volatility is illustrated by the selection of the following 3 charts from the wider set of charts shown in section 4.2. These charts depict the coefficient of variation (standard deviation divided by mean) in the price of spot energy and futures products.

[2] S&P Platts, 19 Dec 2018, *Outlook 2019: UK power sector's Market Making Obligation remains in balance*, available at https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/121918-outlook-2019-uk-power-sectors-market-making-obligation-remains-in-balance

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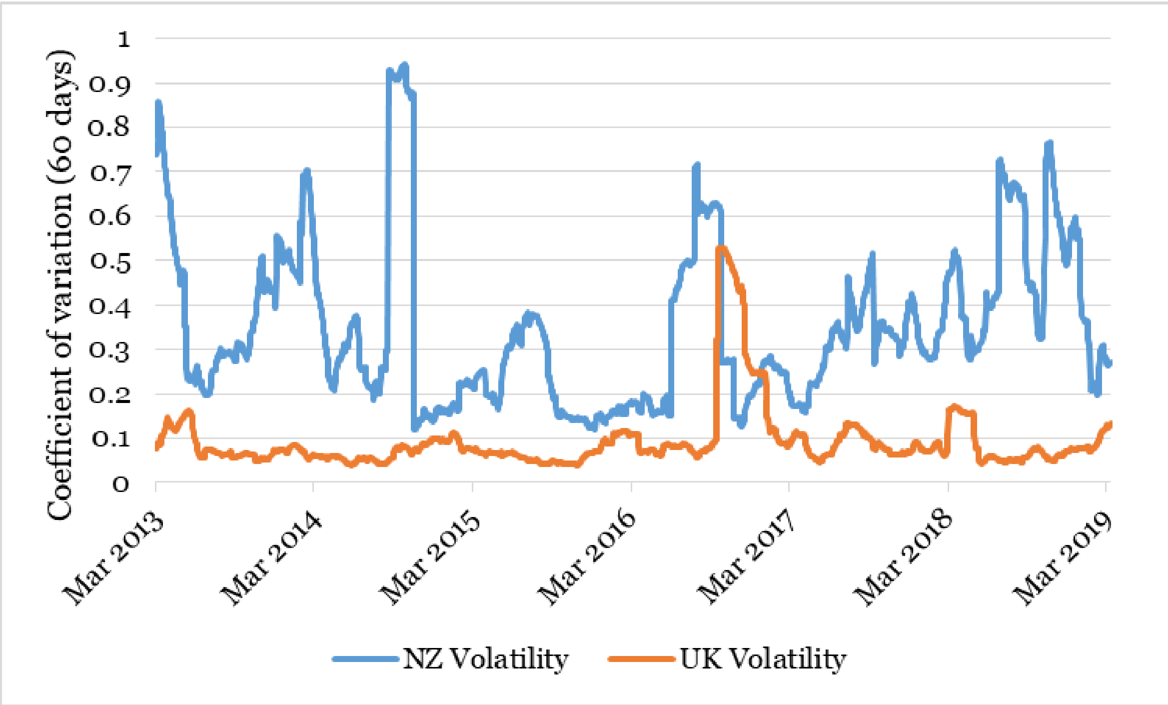
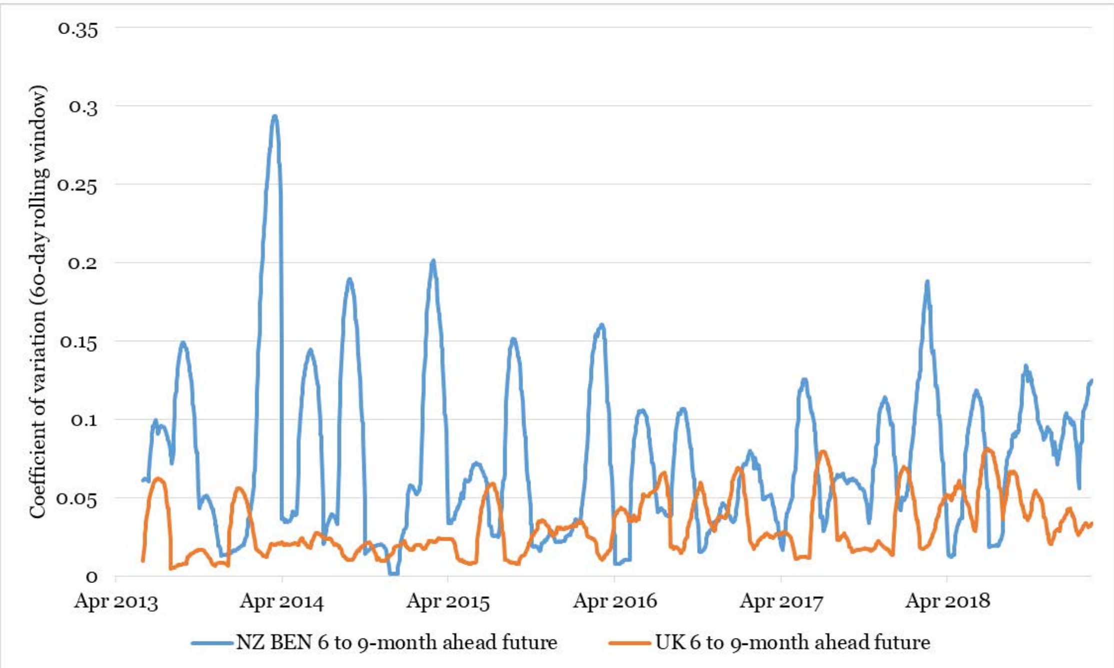
Figure 2-1: NZ vs UK spot price volatility (60 day coefficient of variation)



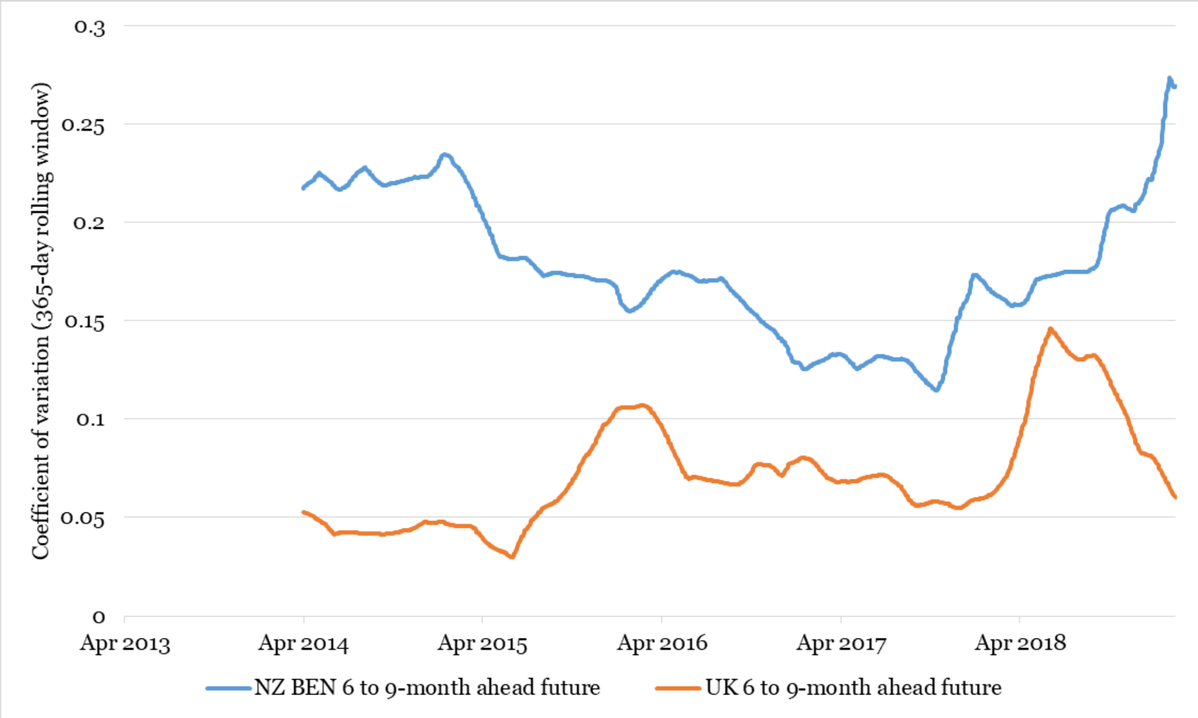
Source: Bloomberg, CEG analysis Source: EMI, Nord Pool, CEG analysis

Figure 2-2: NZ vs UK quarterly futures volatility 6 to 9 months ahead (60 day coefficient of variation)



Source: Bloomberg, CEG analysis Source

Figure 2-3: NZ vs UK quarterly futures volatility 6 to 9 months ahead (365 day coefficient of variation)



Source: Bloomberg, CEG analysis Source

21. This in turn suggests that the UK experience may not be a reliable guide for the likely experience in New Zealand of mandatory market making obligations. It is also worth noting the UK experience with these mandatory obligations has itself been quite problematic and it is uncertain how much longer these obligations will be maintained – as set out in section 4.1.

22. Specifically, based on its December 2017 consultation, Ofgem elected to retain the MMO framework, but proposed make changes to the licence conditions in order to ameliorate the costs incurred by market makers during periods of high volatility. However, the proposed changes have so far not been implemented, as the widespread perceived problems with the MMO have led Ofgem to investigate policy options and alternatives to the MMO for promoting market liquidity.

2.2.3 A strong case for an externality benefit has not been shown

23. It is possible that there are externality benefits from having more predictable access to hedging instruments within a narrower bid-ask spread than would exist absent involuntary obligations. However, a strong case for such benefits that would justify imposing obligations on/subsidising involuntary/voluntary market makers has not been shown.

24. In this context, in 2011 the Electricity Authority identified what it believed were externality benefits from lower bid-ask spreads and performed a cost benefit analysis of imposing market making obligations.[3] Notwithstanding that the analysis was performed at a time when the market was less developed, the Electricity Authority found that there was not a strong efficiency case for imposing market making obligations.

25. Without necessarily endorsing the methodology employed by the Electricity Authority, we consider that a similar process of attempting to establish a materially greater than 1.0 benefit to cost ratio for intervention should be undertaken prior to embarking on specific reforms. Such a process might conclude that no such reform should be implemented. Alternatively, it might help highlight the reform that has the highest benefit to cost ratio.

2.2.4 Fluctuating bid-ask spreads are the norm in financial markets and are not caused by vertical integration

26. The options paper simply presumes that vertically integrated suppliers must bear the costs of market making obligations – either by having mandatory obligations involuntarily imposed or by funding a tender process to select voluntary market makers. However, no justification is provided for imposing this burden on vertically integrated firms.

27. The only rationale provided for the proposal is that bid-ask spreads were unusually high during a period of high uncertainty and volatility in the New Zealand market. However, this is a perfectly normal response to heightened uncertainty in all financial markets and there is no sound basis to argue that this is 'caused' by the existence of vertically integrated businesses. Section 3 provides detailed discussion of the positive relationship between uncertainty/volatility and bid-ask spreads in financial markets from frozen orange juice to crude oil.

28. The fact that bid-ask spreads in the New Zealand electricity futures market behave in the same way as in other financial markets is not surprising and cannot be attributed to the existence of vertical integration between retailers and generators.

29. The Expert Advisory Panel's First Report does provide a rationale for vertical integration lowering liquidity overall when it states that:[4]

> *Vertically integrated companies have no inherent need for contract markets, whereas independent generators and retailers rely on them heavily. If large portions of the generation and retailing sectors have little*

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3 Electricity Authority, Information Paper, Cost Benefit Analysis – Market-Making Obligations, 21 November 2011.

4 Electricity Price Review, First Report, 30 August 2018.

use for contract markets, there will be low liquidity and muffled price signals, making it difficult and costly for independent companies to manage electricity price risks.

30. However, in section 6 of our previous report,[5] we explained that while this logic is intuitive it is fundamentally flawed. In summary, this is because a natural hedge from vertical integration only replaces inframarginal contract hedges. Relative to stand-alone participants, vertical integration does not lower the marginal propensity of generator/retailers to trade in hedge markets in response to changes in prices/economic conditions. It is this marginal propensity to trade that determines liquidity.

31. Indeed, it is reasonable to believe that a vertically integrated generator/retailer is more likely to be more inclined to be a market maker than would its constituent parts were they separated. As noted in our previous report: [6]

> *Indeed, to the extent that there is any reason to believe that liquidity would be affected then it would seem most plausible that it would be increased. This would be the case if the natural hedge provided superior hedging properties relative to external contract hedges. In this case, the merger would reduce the overall risk of the merged entity relative to the (hedged) stand-alone entities. This in turn would improve the merged entity's ability to pursue profits in the hedging market by responding more aggressively to deviations of futures prices from expected spot prices*

2.2.5 Having the ability to provide enhanced liquidity does not imply that the firm should bear those costs alone

32. In order to be able to bear the costs of providing enhanced liquidity to the market a firm must have a strong balance sheet – one that can absorb the volatility of returns that come with being a market maker. In the context of wholesale electricity market, this typically means that the best placed firms to be market makers will be generators. This is not for any other reason than that generators typically have high levels of equity investments in their generation plant while retailers typically choose to run on a lower equity buffer. A well-funded investment bank with diversified income streams (or an independent retailer forming part of a larger group with diversified income streams) could also be well placed to provide market making services (just as happens in other financial markets).

33. As noted in our previous report, it is these balance sheet decisions that typically mean retailers with skinny balance sheets attempt to rely on the balance sheets of generators. [7]

[5] CEG, Competition in New Zealand Electricity Markets, October 2018.

[6] CEG, Competition in New Zealand Electricity Markets, October 2018, p. 54.

> *In this equilibrium, retailers are effectively shifting some of their risk to generators. Generators are better able to bear this risk given their stronger balance sheets, and the hedge market provides a means for retailers to, in effect, make use of generators' balance sheets. However, retailers must pay generators for this privilege – with the premium in hedge contracts relative to expected spot prices effectively a 'rental charge' for using generators' balance sheets (convincing generators to over hedge in aggregate).*

34. In addition to this, a vertically integrated generator may be even better placed than a stand-alone generator to provide market making services due to the considerations outlined at paragraph 31 above.

35. However, the fact that vertically integrated generators may be best placed to provide market making services is no justification for imposing an unfunded obligation on them to do so. Rather, to the extent that it is believed that the market as a whole will operate more efficiently with lower bid-ask spreads then market participants as a whole should fund the costs of achieving this.

36. For example, a per MWh levy could be placed on all retailers and generators. The proceeds of this could be used to fund a tender process that selected market makers willing to take on a set of clearly defined obligations. Generators and investment banks could participate in such a tender process. Even if mandatory obligations were to be imposed on specific participants without any tender, such a fund could be used to compensate for the actual or expected costs of the obligations so imposed.

37. This would avoid the shortcomings that of the framework implemented by Ofgem in the UK. In particular, Ofgem's framework resulted in considerable losses for market makers, which are likely to be magnified if the same framework were to be applied in New Zealand. In that context, Drax (a UK generation company that is not subject to a market making obligation) made a similar suggestion in its response to Ofgem's open letter in August 2018:[8]

> *We support Ofgem's decision to pause and reflect on the objectives of the Secure and Promote Licence Condition in light of changing market conditions. A suspension of the Market Making Obligation (MMO) will ensure the remaining obligated parties do not incur disproportionate costs and provide an opportunity to assess the impact of the MMO's removal. This is a reasonable action consistent with Ofgem's previous guidance, the*

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7 CEG, Competition in New Zealand Electricity Markets, October 2018, p. 110.

8 Drax, Secure and Promote: Response to open letter dated 9th August 2018, Letter to Ofgem, 20 September 2018.

original evidence supporting the Secure and Promote programme and the final decision to introduce the MMO.

We agree that the MMO should be suspended ahead of the winter period, rather than during it. This will enable the market to adjust to new arrangements ahead of the winter peak, avoiding the potential for complicated changes during a traditional period of market tightness.

We also support a review of the underlying requirement for a Market Maker during 2019. Should it be necessary to continue with a Market Maker function, then ***we support the development of a reasonable and proportionate model, such as a tendered service with costs socialised across all market participants****.*

2.2.6 Industry funding promotes efficient design

38. The user-pays nature of an industry funded scheme will also promote the efficient design of the scheme. If mandatory obligations are to be imposed on only a subset of participants then other participants have a strong incentive to promote high cost solutions because they have the most to gain (e.g., from trading with the market maker at unrealistically low bid-ask spreads relative to the inherent risk). If all participants have to fund the expected or actual costs of the scheme then this incentive is dampened and participants have, instead, an incentive to design a scheme that maximises the benefit to cost ratio (because they are paying the 'cost' denominator of this ratio).

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3 Literature review and empirical analysis

39. In this section we conduct a review of literature regarding the relationship between bid-ask spreads (BAS) and pricing volatility, as well as the roles fulfilled by market makers. The key conclusions that we draw from the literature are:

- Economic theory predicts a positive relationship between bid-ask-spreads and the underlying uncertainty in the value of the asset being traded. Specifically, that the costs of being a market maker increase with uncertainty; and
- There is strong empirical support for this theoretical finding.

3.1 Market makers and bid-ask spreads

40. Bagehot (1971)[9] describes the economics of market making, whereby the market maker transacts with three types of traders: (1) transactors with special information; (2) those who transact for "liquidity reasons" (i.e., trades based on some fundamental objective other than a belief that the asset is mispriced (e.g., sales of stocks in order to obtain cash for consumption purposes or purchases of hedging instruments for solely for the purpose of hedging without a view as the fair price of that hedge); and (3) transactors who incorrectly perceive themselves as having special information that in actual fact has already been priced into the market.[10]

41. According to Bagehot (1971), market makers typically lose money to category (1) transactors in a process that is referred to as "adverse selection", while recouping such losses through gains from transactors in categories (2) and (3). The bid-ask spread plays an important function in the context of this mechanism, since a wider spread minimises the market maker's losses by discouraging trades by category (1) transactors, but also reduces gains from categories (2) and (3) transactors.

42. The greater the uncertainty/volatility in the true underlying value of a stock the greater is the potential loss to category (1) traders. Therefore, other things equal, the expected cost of being a market maker rises with uncertainty in the true value of the asset being traded.

43. Under this framework, the market maker's incentive is to determine the price that equilibrates buy and sell pressures, rather than risk making informational errors based on fundamental information. The market maker must set bid-ask spreads

9 "Bagehot" is the author's pen name (named for 19th century financial journalist Walter Bagehot). The author's actual name is Jack Treynor (of Treynor Capital Management).

10 Bagehot, The Only Game in Town, Financial Analysts Journal, March-April 1971, pp. 12-14, 22.

(analogous to the market maker's price) in a manner that allows it to profit by earning more from transactors (2) and (3) than it loses to transactors (1):

> *If trading volume is small, and insiders' profits are large, the spread cost incurred in transacting is necessarily large, however. Whereas it is indeed true that the transactor is as likely to gain as lose from fluctuations in equilibrium value, what he loses in trading against the spread must be large enough to provide insiders with their profits, and hopefully leave something for the market maker besides.*

44. Glosten and Milgrom (1985) build on Bagehot's (1971) framework by constructing a mathematical model that investigates the drivers of bid-ask spreads.[11] This model features investors that approach market makers one by one and choose whether or not to participate in the market after observing the bid-ask spreads set by the market maker.

45. The model shows that the ask price increases and the bid price decreases when:

    - Insider information (from category (1) transactors) improves;
    - The ratio of informed to uninformed users increases; and
    - The elasticities of supply and demand among uninformed users increases.

46. Glosten and Milgrom (1985) note that:

> *… the expected value of the squared average spread times volume has a uniform bound (independent of the pattern of trade) that is related to the variance of the underlying uncertainty. The proposition is proved using the observations that the variance of the price at each trade is roughly proportional to the squared spread, and the total variance of prices from trade to trade is bounded by the variance of the underlying value of the security.*

47. The framework discussed by Bagehot (1971) and formalised by Glosten and Milgrom (1985) shows that variations in bid-ask spreads are a fundamental element of market making and that this variation is correlated with the level of uncertainty in the value of the underlying asset. Market makers must adjust the spreads in order to ensure that the losses they sustain from informed traders are adequately compensated by corresponding gains from liquidity transactors and uninformed traders.

48. Glosten and Milgrom (1985) note that the expected cost of being a market maker may be so high that trading is not profitable under any bid-ask spread.

---

11 Glosten and Milgrom, Bid, ask and transaction prices in a specialist market with heterogeneously informed traders, Journal of Financial Economics, vol. 14, 1985, pp. 71-100.

> *In the introduction, we described the theoretical possibility that markets might close down entirely, with the bid price being set so low and the ask price so high as to discourage any trade. This problem is identical to the famous lemons problem of Akerlof (1970), in which adverse selection can destroy the market.*

49. The key point here is that market making is costly and that the costs of providing the service vary over time and with market circumstances. That cost is reflected in the bid-ask spread and the bid-ask spread must be able to move to reflect that cost. If an obligation on market makers restricts their ability to vary the bid-ask spread to reflect variations in cost then the obligations will impose losses, and potentially very high losses, on the market makers who bear those obligations.

3.2 Empirical literature on bid-ask spreads and pricing volatility

50. This section summarises the empirical literature on the relationship between bid ask spreads and uncertainty.

Table 3-1: Summary of empirical literature

Authors	Title	Year Journal	Method	Result
McInish and Wood	An Analysis of Intraday Patterns in Bid/Ask Spreads for NYSE Stocks	1992 The Journal of Finance	Linear regression with explanatory variables for number of transactions, size of trades, two measures of risk, number of shares per trade, trading on regional exchanges, and dummy variables for intra-day intervals and days of the week	The level of spreads is found to be significantly inversely related to two measures of activity, the number of trades and the number of shares per trade. The level of spreads is directly related to both differential risk across stocks and differential risk across intervals of the trading day. Intervals of the trading day during which there are trades of an unusually large size have higher spreads reflecting the information content of these trades.
Lawrence Glosten and Lawrence Harris	Estimating the Components of the Bid/Ask spread	1988 Journal of Financial Economics	Calculate bid ask spread based on changes in prices. Estimating that on dummy variable for whether transaction is buy or sell and other explaining variables.	The result finds that bid ask spread is positively correlated with weekly return standard deviation and percentage of shares held by insiders.
Andros Gregoriou, Christos Ioannidis and Len Skerratt	Information Asymmetry and the Bid-Ask Spread: Evidence from the UK	2005 Journal of Business Finance & Accounting	Linear regression against the variance of analyst forecasts, variance of monthly returns, market value of the firm, and trading volume.	We find that both volatility of returns and disagreement amongst analysts regarding earnings are significant are positive in explaining FTSE 100 company spreads.
Tim Bollerslev and Michael Melvin	Bid-ask spreads and volatility in the foreign exchange market	1994 Journal of International Economics	First estimate the conditional variance of the spot exchange rate using a GARCH(1,1) process. Categorise the observed bid ask quote spread into discrete bins. Ordered probit estimation of spread distribution on explaining variables with MA1 and Garch(1,1)	There is a significantly positive effect of exchange rate volatility on the spread. Assuming there are four spread categories. If the conditional variance of the exchange rate increases by one standard deviation, then the probability of being in the highest spread category increases 4.1% and second highest category by 10.3%
Julieta Frank and Philip Garcia	Bid-Ask Spreads, Volume, and Volatility: Evidence from Live	2010 American Junior of Agricultural Economics	Construct four measures of bid-ask spread a) RM serial covariance – covariance of current and previous price change b) TW estimator - Average size of price change over a period	The volatility of transaction prices is positively correlated with spread when it is estimated using RM, TW, and ABS. Negative correlation when it is HAS Using ABS, a one unit increase in the log of standard deviation of prices over a day increases the half bid ask spread for that day by 7.7 to 10.1 cents per lb.

	Stock Markets		c) HAS – estimated half bid-ask spread using MCMC d) ABS- a variation of Roll's model Calculate volatility based on log of standard deviation of prices over a day. Estimate the bid-ask spread proxy of determinants using GMM IV	
George Wang and Jot Yau	Trading Volume, Bid-Ask Spread, and Price Volatility in Futures Markets	2000 Journal of Futures Markets	Obtain the daily average bid ask quote spread. Estimate spread, daily volatility and volume on each other and past variables and others.	The coefficients of price volatility on spread were significantly positive for all four futures. In terms of magnitude, the elasticities of spread with respect to price volatility were higher for financial futures than metals.
David Ding	The Determinants of Bid-Ask Spreads in the Foreign Exchange Futures Market	1999 Journal of Futures Market	Linear regression based on McInish and Wood's (1992) study with modified variables	It is found that the number of transactions and the volatility of FXF prices are the major determinants. The number of transactions is negatively related to the BAS, whereas volatility in general is positively related to it.

3.2.1 Detailed discussions of articles

51. The literature is clear that pricing volatility/uncertainty is a positive driver of BAS.

52. McInish and Wood (1992) refer to findings from earlier literature that conclude that BAS is heavily affected by the risks being faced by a dealer or market maker:[12]

> *Researchers examining trading costs find that a dealer's risk of holding a security is a significant determinant of the bid-ask spread; these researchers use measures of total risk (Tinic (1972), Tinic and West (19721, Branch and Freed (1977), Hamilton (1978), Stoll (1978)) and of systematic and unsystematic risk (Benston and Hagerman (1974), Stoll (1978)). Given these considerations, the following hypothesis would be expected to hold.*
>
> *Hypothesis 2: **There is a direct relationship between the level of risk and spreads**.*

53. McInish and Wood (1992) then carry out their own empirical study using intra-day NYSE data from January to June 1989, divided into 30-minute intervals. They conclude that spreads are directly related to cross-sectional and time series risks:[13]

> *The level of spreads is found to be significantly inversely related to two measures of activity, the number of trades and the number of shares per trade. The level of spreads is directly related to both differential risk across stocks and differential risk across intervals of the trading day. Intervals of the trading day during which there are trades of an unusually large size have higher spreads reflecting the information content of these trades.*

54. Ding (1999) cites the results from McInish and Wood (1992), and also cites other literature that produce similar results in other financial markets:[14]

> *In the equity market, McInish and Wood (1992) show that intraday BASs depend negatively on the level of activity and market competition, and positively on the level of risk and information. In the foreign exchange market, Boothe (1988) finds that different measures of risk and transactions volume have an impact on BASs. Specifically, he provides evidence for a positive relationship between the level of uncertainty*

12 McInish and Wood, An Analysis of Intraday Patterns in Bid/Ask Spreads for NYSE Stocks, The Journal of Finance, vol. 42(2), June 1992, pp. 753-764, at p. 754.

13 McInish and Wood, An Analysis of Intraday Patterns in Bid/Ask Spreads for NYSE Stocks, The Journal of Finance, vol. 42(2), June 1992, pp. 753-764, at p. 762.

14 Ding, The Determinants of Bid-Ask Spreads in the Foreign Exchange Futures Market: A Microstructure Analysis, The Journal of Futures Markets, vol. 19(3), 1999, at pp. 310-311.

regarding future prices and BASs. The relationship between trading volume and BASs is found to be negative.

In the futures market, Ma, Peterson, and Sears (1992) examine various measures of BASs on different futures contracts and find that spread levels are significantly higher at the beginning and end of a trading session. They provide the explanation of higher levels of trading noise and information uncertainty during those periods. However, these phenomena can be caused by infrequent trading.

Wang, Michalski, Jordan, and Moriarty (1994) investigate the determinants of the bid-ask spread and price volatility of S&P 500 index futures that are traded on the Chicago Mercantile Exchange. They find that the major factors affecting BASs are the price risk, trade volume, and market competition. They also find a U-shaped pattern in BASs. However, they realize that this pattern is not significant after adjusting for the effects of price volatility, transaction volume, and market competition.

55. Ding (1999) follows up with an empirical study of transaction data for deutsche mark (294,502 price change observations) and Japanese Yen (281,980 price change observations) futures contracts in 1990. The regression results concur with McInish and Wood (1992) that "volatility in general is positively related" with intraday BAS.

56. Wang and Yau (2000) also conduct a literature review of the relationship between BAS and price volatility, all of which show a positive relationship:[15]

Roll (1984), French and Roll (1986), Glosten (1987), and others derived a relationship between the standard deviation of equilibrium price changes and the BAS for a particular data-generating process. Cohen, Maier, Schwartz, and Whitcomb (1986) reviewed previous empirical studies of the relationship between transaction price volatility and BASs in securities markets. In general, these studies found a positive relationship between transaction price volatility and BASs when price change was measured over short intervals (e.g., daily). The relationship became insignificant for price changes measured over longer intervals (e.g., monthly). Recently, Amihud and Mendelson (1987) demonstrated the existence of a positive relationship at the closing hour of the NYSE. None of these empirical studies controlled for the information effect on volatility.

Harris (1987) incorporated both liquidity and information effects and found an inverse relationship between transaction price volatility and liquidity. However, liquidity was not measured directly by the BAS but by a set of hypothesized explanatory variables.

[15] Wang and Yau, Trading Volume, Bid-Ask Spread, and Price Volatility in Futures Markets, The Journal of Futures Markets, vol. 20(10), 2000, pp. 943-970 at pp. 948-949.

Wang et al. (1994), using direct estimates of the BAS, examined the intraday relationship of BASs and price volatility in the S&P 500 index futures market and controlled for information and liquidity effects. They found that BASs and price volatility are jointly determined and positively related.

57. Wang and Yau (2000) then conduct an empirical study on four financial and metal futures, using a number of statistical techniques (such as Hausman tests and generalised method of moments (GMM)) to improve on the rigour of the findings in earlier literature. Their model strengthens the conclusion that price volatility is positively associated with BAS.

58. Gregoriou *et al* (2005) empirically estimate the drivers of bid-ask spreads using stock data for 26 firms chosen from the FTSE index. They find that bid-ask spreads are positively and significantly correlated with the volatility of returns and disagreements among analysts. That is, increased uncertainty results in higher bid-ask spreads due to market makers having to protect themselves:[16]

We find that both volatility of returns and disagreement amongst analysts are significant (with the hypothesised signs) in explaining FTSE 100 company spreads. The volatility captures information uncertainty concerning the current period to the year end. Since company returns are affected by the market in general, it is also likely that volatility reflects economy wide aspects of uncertainty. However, our results show that the disagreement amongst analysts is also significant. What interpretation should be placed on this? First, it is worth noting that disagreement is more likely to be related to firm specific issues in contrast to the volatility measure which is likely to be driven by market wide factors. As a consequence, disagreement amongst investors may be related to the probability of poor results over and above the information contained in the volatility of returns. Such performance is well known to cause delays in reporting the year end results and to cause additional information asymmetry between market makers and investors. The market makers in turn increase their spread in order to protect themselves as modelled in Kim and Verrecchia (2001).

59. Frank and Garcia (2010) analyse the relationship between bid-ask spreads and its determinants in the market for agricultural futures. Specifically, they apply Bayesian techniques on futures contracts for lean hogs and live cattle between January 2005 and October 2008. Similar to the results found in previous literature,

16 Gregoriou, Ioannidis and Skerratt, Information Asymmetry and the Bid-Ask Spread: Evidence From the UK, Journal of Business Finance & Accounting, vol. 32(9)-(10), November-December 2005, pp. 1801-1826 at p. 1823.

Frank and Garcia (2010) conclude that volatility increases risk, which leads to higher bid-ask spreads:[17]

> *Volume and volatility appear to be the most important determinants of the bid-ask spread. For both commodities the direction of the effects of total volume and volatility are consistent with findings by Thompson and Waller (1987), Thompson, Eales, and Seibold (1993), and Bryant and Haigh (2004). The cost of liquidity depends on scalpers' risk of holding positions. Higher traded volume implies lower time between trades and therefore lower risk for scalpers. In contrast, higher price volatility is associated with a higher risk of holding a position.*

60. Bollerslev and Melvin (1994) carry out an empirical analysis of Deutschemark/US dollar spot rates. Their model, which uses a GARCH type equation to quantify spot exchange uncertainty, finds a positive relation between bid-ask spreads and underlying exchange rate uncertainty:[18]

> *Measuring exchange rate volatility as the conditional variance of the ask price estimated by an MA(1)-GARCH(1, 1) model, we find that there is a strong positive relationship between volatility and spreads. The coefficient estimates of the effect of the conditional variance on the spread are highly statistically significant. Simulating the effects of a one standard deviation increase in volatility also indicates a stong* [sic] *economic effect on the spread. For instance, using all the observations, if the volatility increases by one standard deviation, the probability that the next quote will fall in the lowest spread category declines by almost 11 percent points.*

3.3 CEG estimates from selected markets

61. In this section we carry out an empirical analysis of the bid-ask spreads (BAS) for a selection of futures with different underlying asset classes, focusing specifically on the correlation between BAS and a measure of price volatility.

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17 Frank and Garcia, Bid-Ask Spreads, Volume, and Volatility: Evidence from Livestock Markets, American Journal of Agricultural Economics, January 2011, pp. 209-225 at p. 222.

18 Bollerslev and Melvin, Bid-ask spreads and volatility in the foreign exchange market: An empirical analysis, Journal of International Economics, vol. 36, 1994, pp. 355-372 at pp. 370-371.

3.3.1 Methodology

62. We obtain historical daily bid, ask, and last price data for the following set of futures from Bloomberg: [19]

- Copper: HG1 Comdty;
- Crude oil, WTI: CL1 Comdty;
- Corn: C 1 Comdty;
- Frozen concentrated orange juice: JO1 Comdty;
- Iron ore: IOE1 Comdty;
- UK monthly peak electricity (Gregorian): IPE1 Comdty;
- Nordic electricity: NEX1Y Comdty; and
- Natural gas: NG1 Comdty.

63. We measure price volatility as the standard deviation of last prices over a rolling window of 60 calendar days, which we then compare against the average BAS over the same rolling window.

3.3.2 Results

3.3.2.1 Copper

64. The BAS and price volatility time series for copper are shown in Figure 3-1, while the corresponding scatterplot is shown in Figure 3-2.

65. The time series shows that BAS and volatility were both low prior to January 2006, after which there has been an elevation in both BAS and volatility. Using the same data in a scatterplot shows a clear positive relationship between BAS and price volatility. The correlation between the two series is **0.25**.

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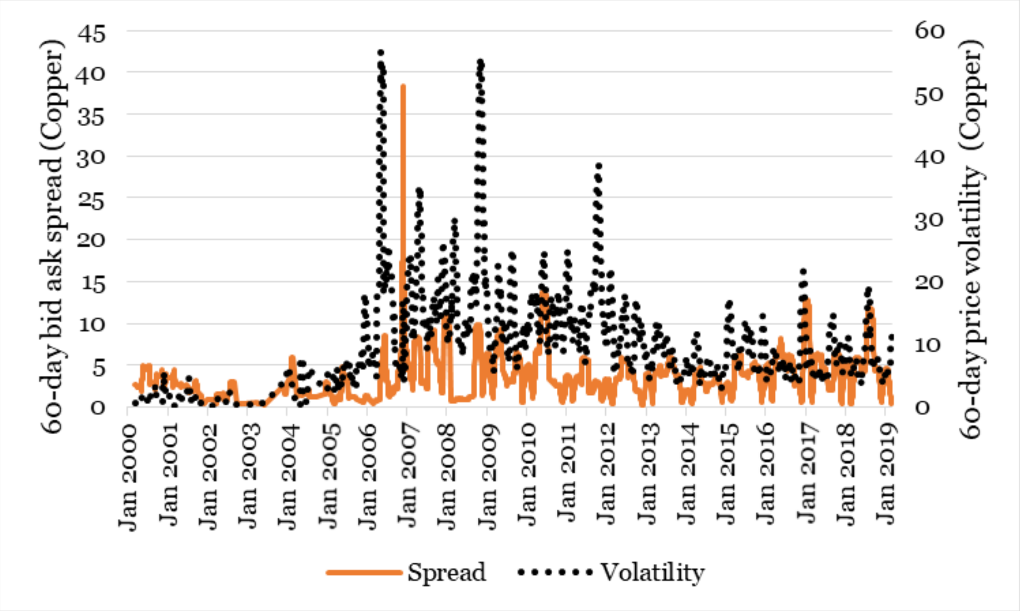
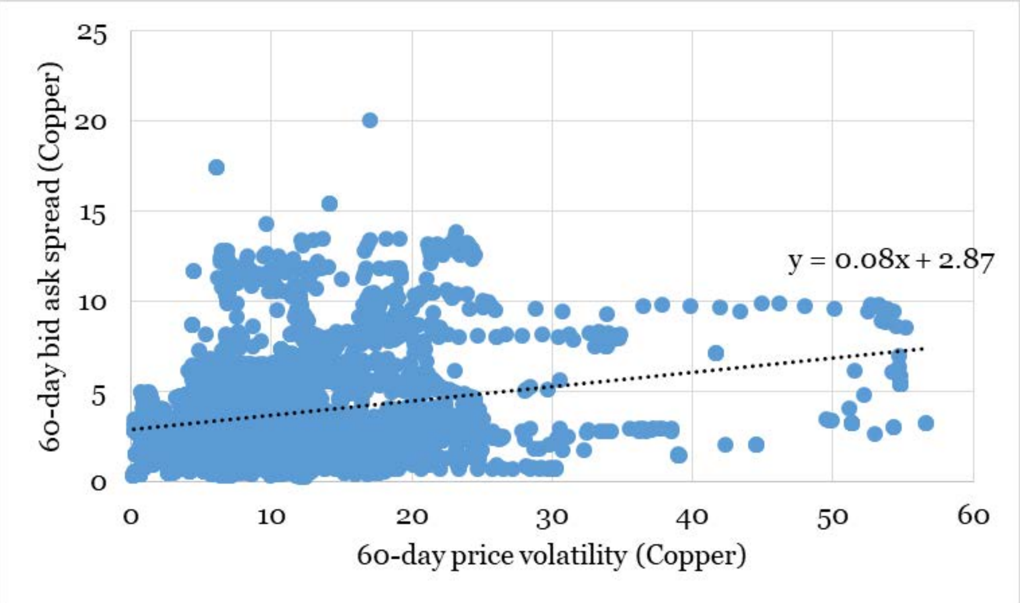
[19] These are "Generic 1st" futures published by Bloomberg. These series are created by combining quarterly futures for the same underlying asset into a single series. At each observation, Bloomberg takes the future with the closest expiration date that has not occurred yet.

Figure 3-1: Time series of BAS and price volatility (copper)



Source: Bloomberg; CEG analysis

Figure 3-2: Scatterplot of BAS against price volatility (copper)

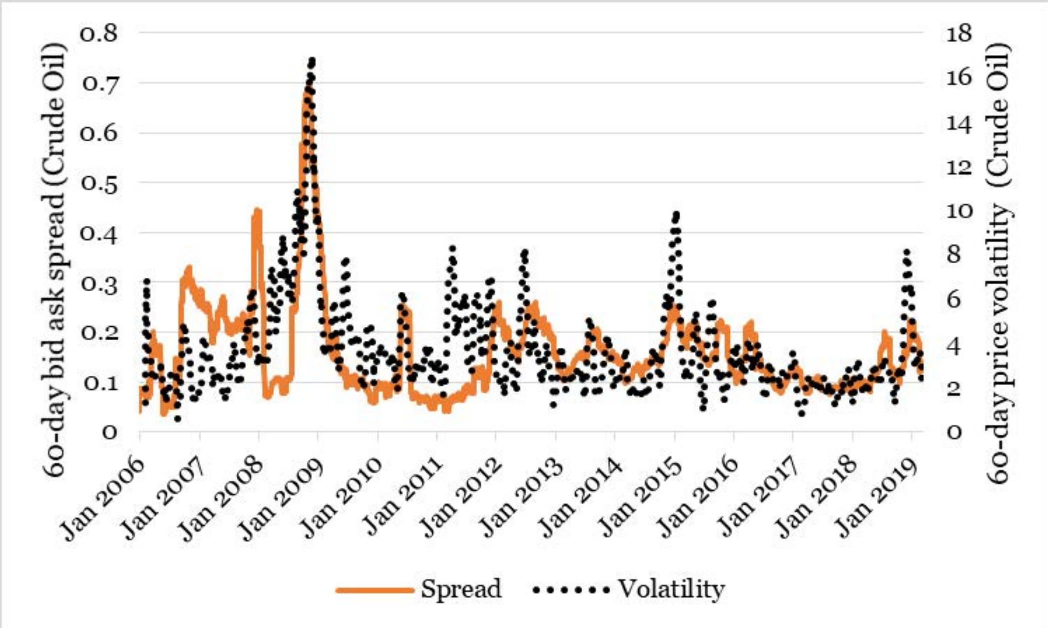


Source: Bloomberg; CEG analysis

3.3.2.2 Crude oil

66. The BAS and price volatility time series for crude oil are shown in Figure 3-3,[20] while the corresponding scatterplot is shown in Figure 3-4. The time series shows a strong correlation between BAS and price volatility, which can also be seen in the scatterplot. The correlation between the two series is **0.45**.

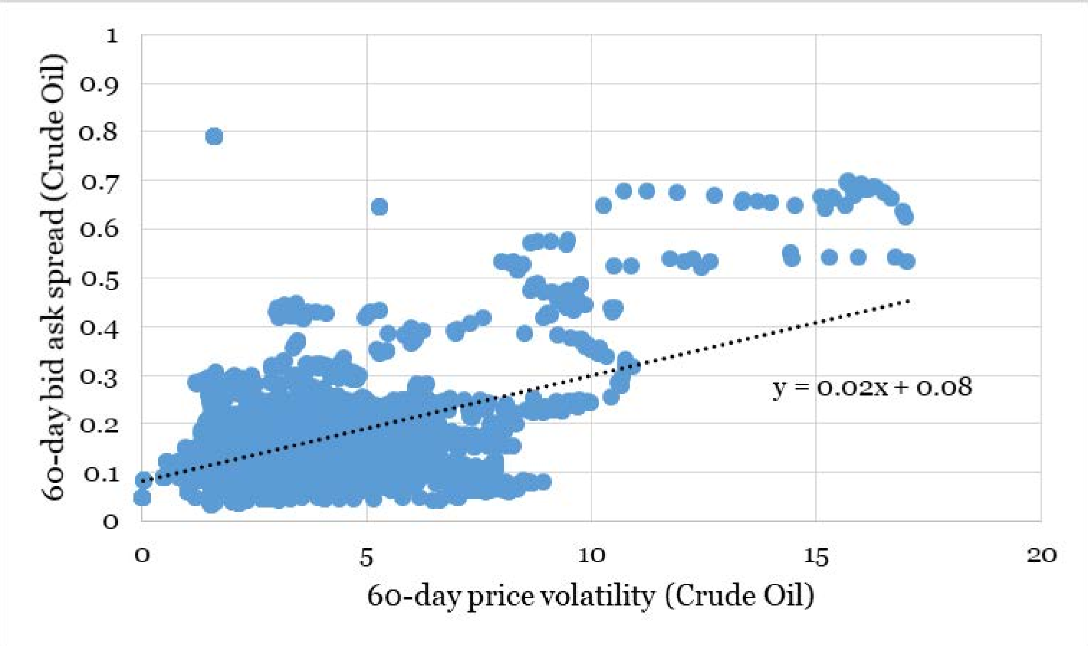
Figure 3-3: Time series of BAS and price volatility (crude oil)



Source: Bloomberg; CEG analysis

20 We omitted pre-2006 data because Bloomberg's bid and ask records were very sparse before that time period.

Figure 3-4: Scatterplot of BAS against price volatility (crude oil)

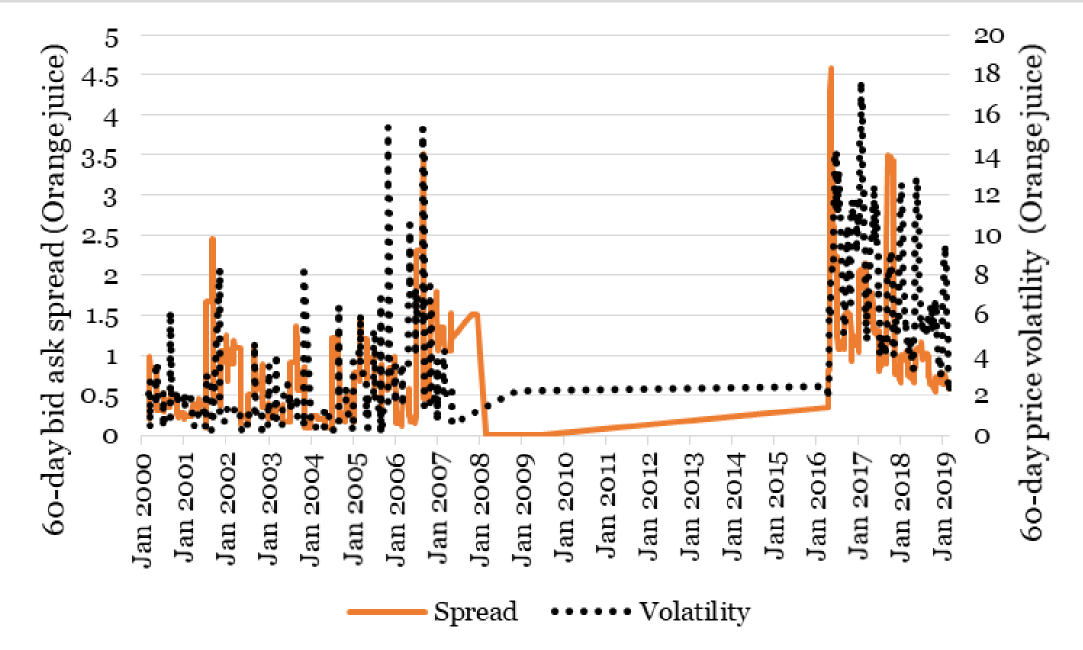


Source: Bloomberg; CEG analysis

3.3.2.3 Frozen concentrated orange juice

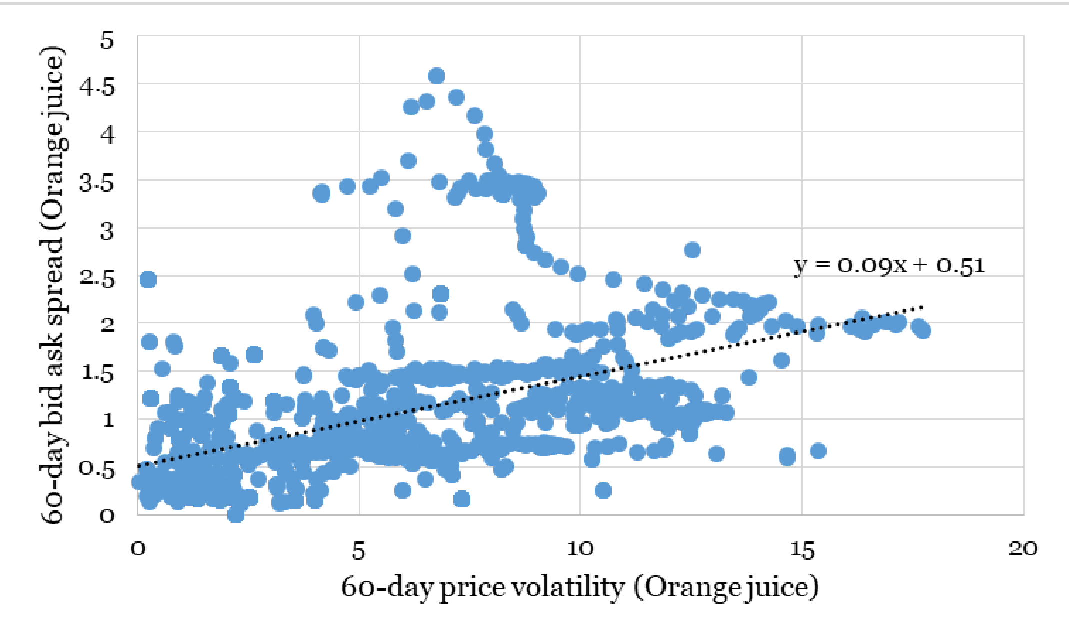
The BAS and price volatility time series for frozen concentrated orange juice are shown in Figure 3-5, while the corresponding scatterplot is shown in Figure 3-6. The necessary data is unavailable from Bloomberg from 2007 to 2016. However, outside this period both series show general increases in level from mid-2004 to mid-2006, while declining from mid-2016 onwards. The scatterplot shows a positive relationship between BAS and price volatility. The correlation between the two series is **0.49**.

Figure 3-5: Time series of BAS and price volatility (orange juice)



Source: Bloomberg; CEG analysis

Figure 3-6: Scatterplot of BAS against price volatility (orange juice)

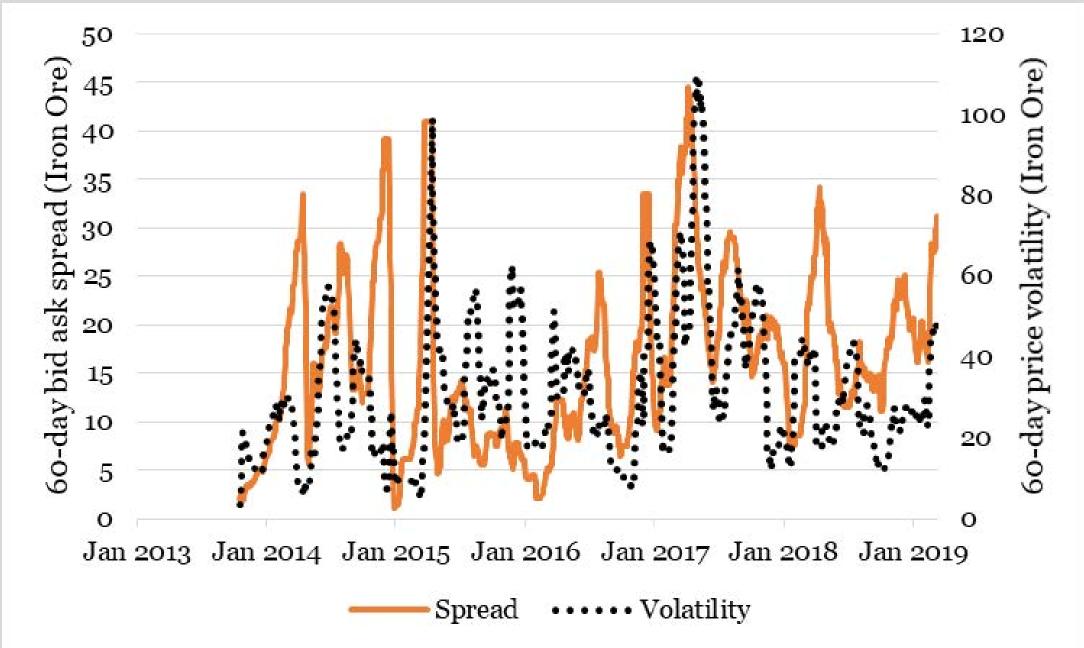


Source: Bloomberg; CEG analysis

3.3.2.4 Iron ore

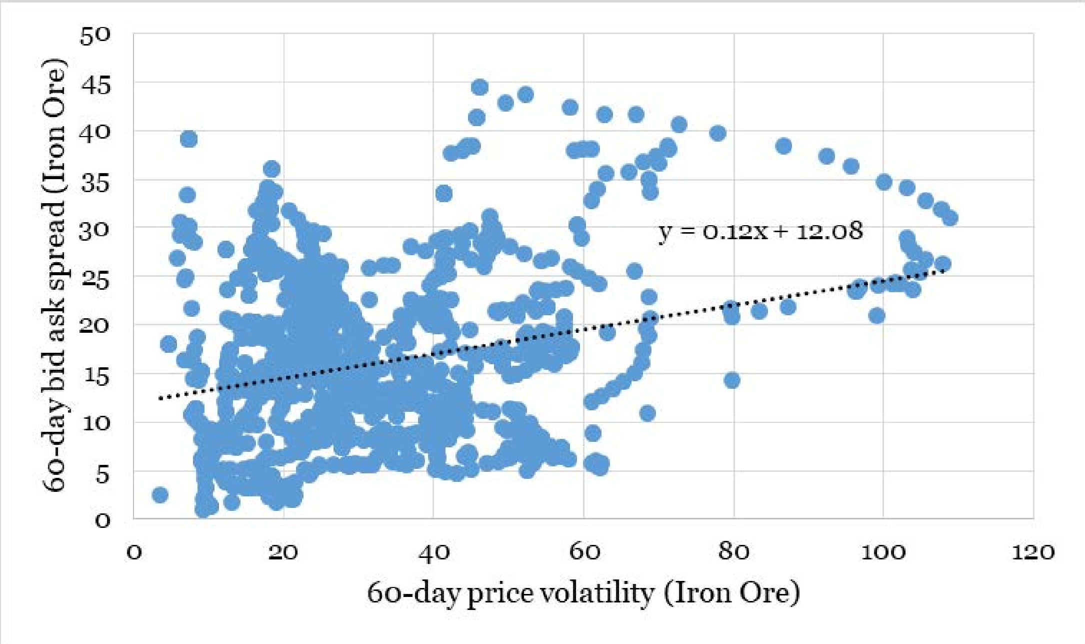
67. The BAS and price volatility time series for iron ore are shown in Figure 3-7, while the corresponding scatterplot is shown in Figure 3-8. The time series plot shows that the two highest peaks for BAS and price volatility occur at approximately the same time in mid-2015 and mid-2017. The scatterplot shows a positive relationship between BAS and price volatility. The correlation between the two series is **0.25**.

Figure 3-7: Time series of BAS and price volatility (iron ore)



Source: Bloomberg; CEG analysis

Figure 3-8: Scatterplot of BAS against price volatility (iron ore)

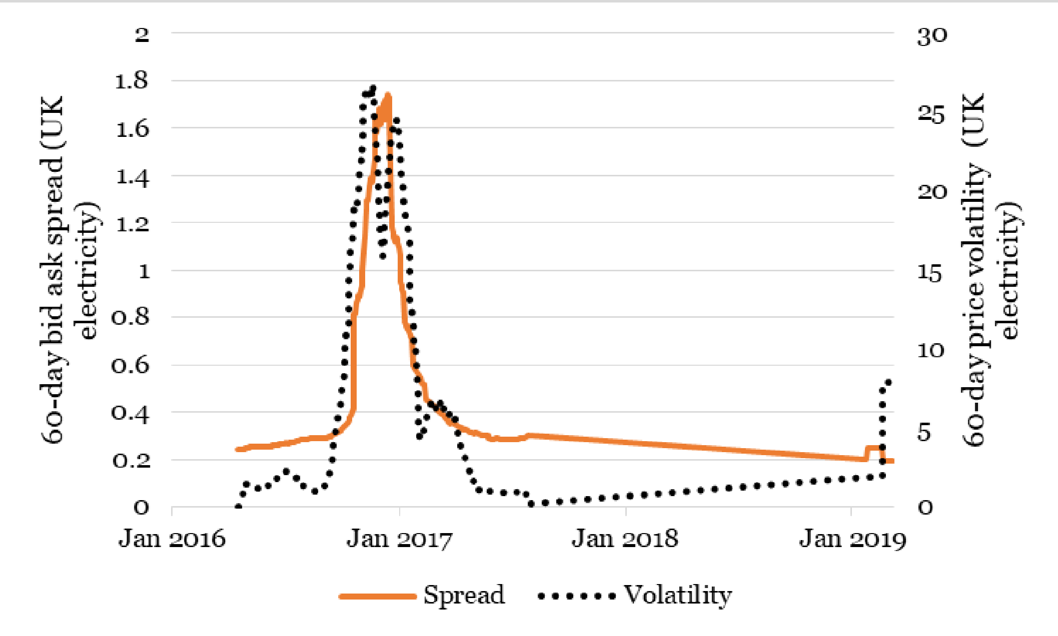


Source: Bloomberg; CEG analysis

3.3.2.5 UK monthly peak electricity

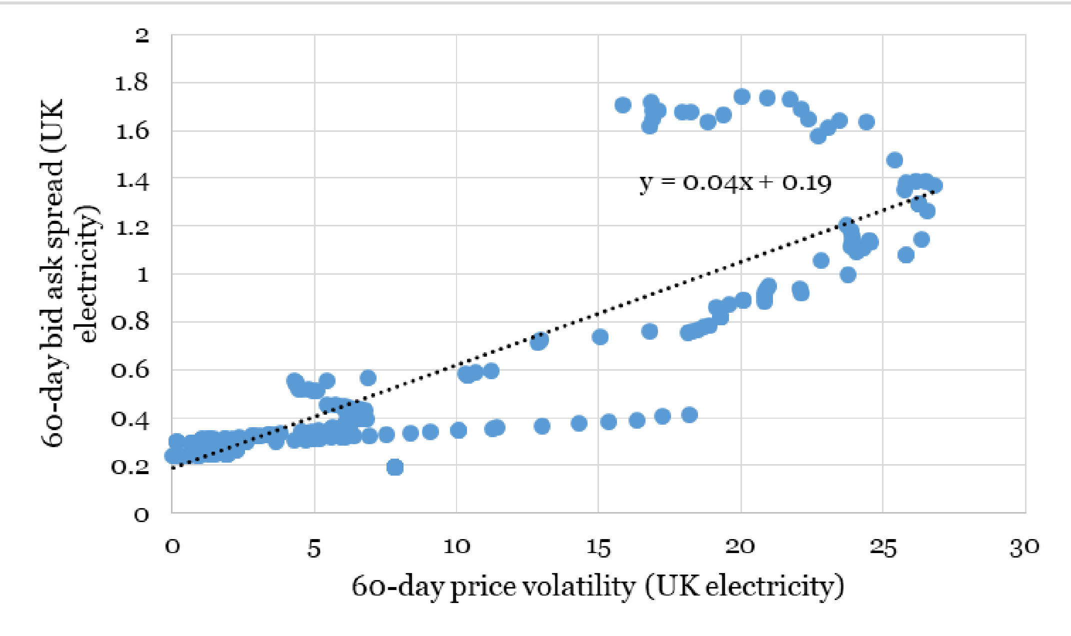
68. The BAS and price volatility time series for UK monthly peak electricity are shown in Figure 3-9, while the corresponding scatterplot is shown in Figure 3-10. Bid and ask data is unfortunately sparse after mid-2017, but for the time periods where data is available from mid-2016 to mid-2017, BAS increase with volatility. The scatterplot shows a positive relationship between BAS and price volatility. The correlation between the two series is **0.87**.

Figure 3-9: Time series of BAS and price volatility (UK electricity)



Source: Bloomberg; CEG analysis

Figure 3-10: Scatterplot of BAS against price volatility (UK electricity)

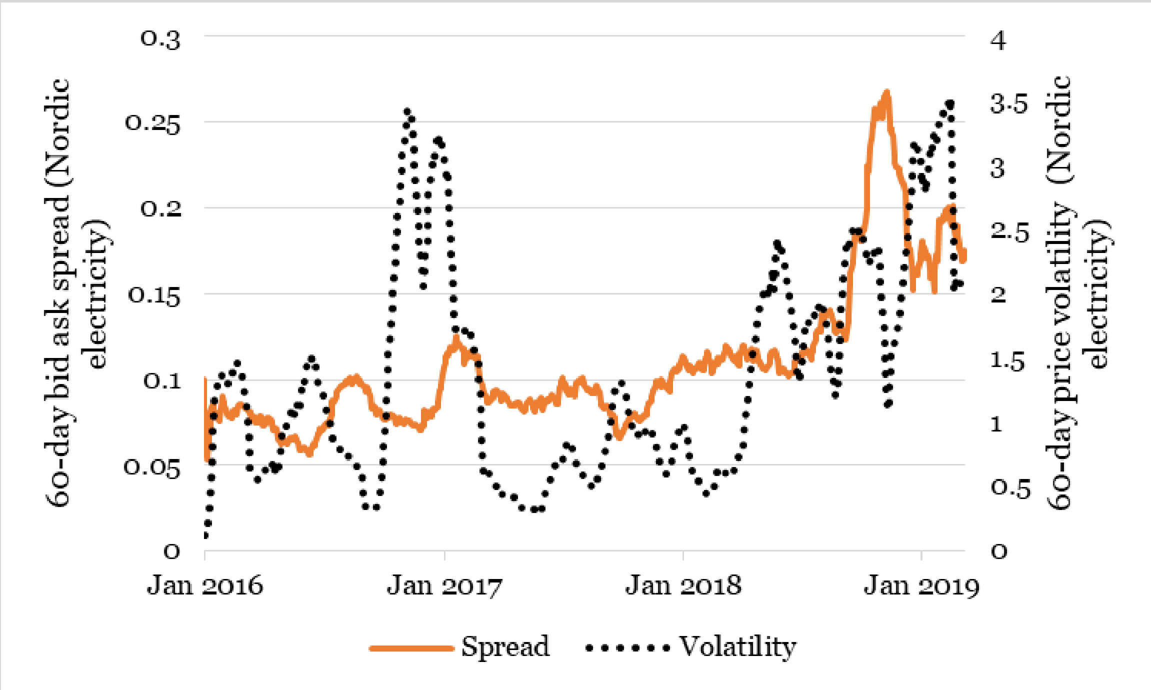


Source: Bloomberg; CEG analysis

3.3.2.6 Nordic electricity

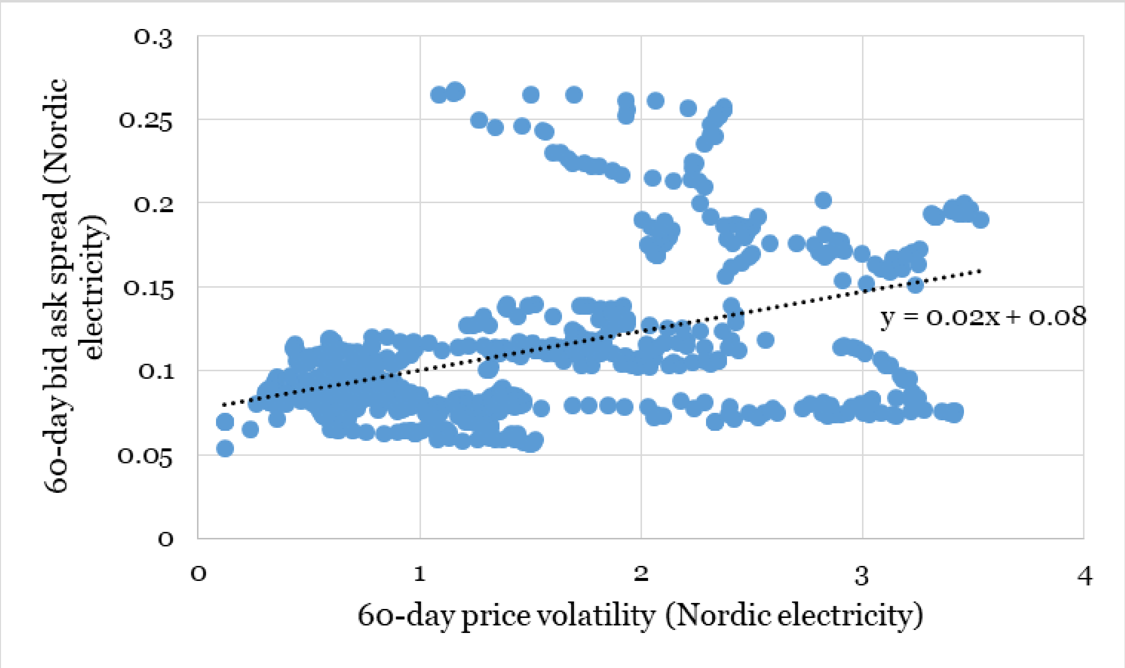
69. The BAS and price volatility time series for Nordic electricity are shown in Figure 3-11, while the corresponding scatterplot is shown in Figure 3-12. The time series plot shows an increasing trend in both BAS and price volatility, particularly from mid-2018 onwards, although the movements in both series do not match perfectly. The scatterplot shows a positive relationship between BAS and price volatility. The correlation between the two series is **0.46**.

Figure 3-11: Time series of BAS and price volatility (Nordic electricity)



Source: Bloomberg; CEG analysis

Figure 3-12: Scatterplot of BAS against price volatility (Nordic electricity)

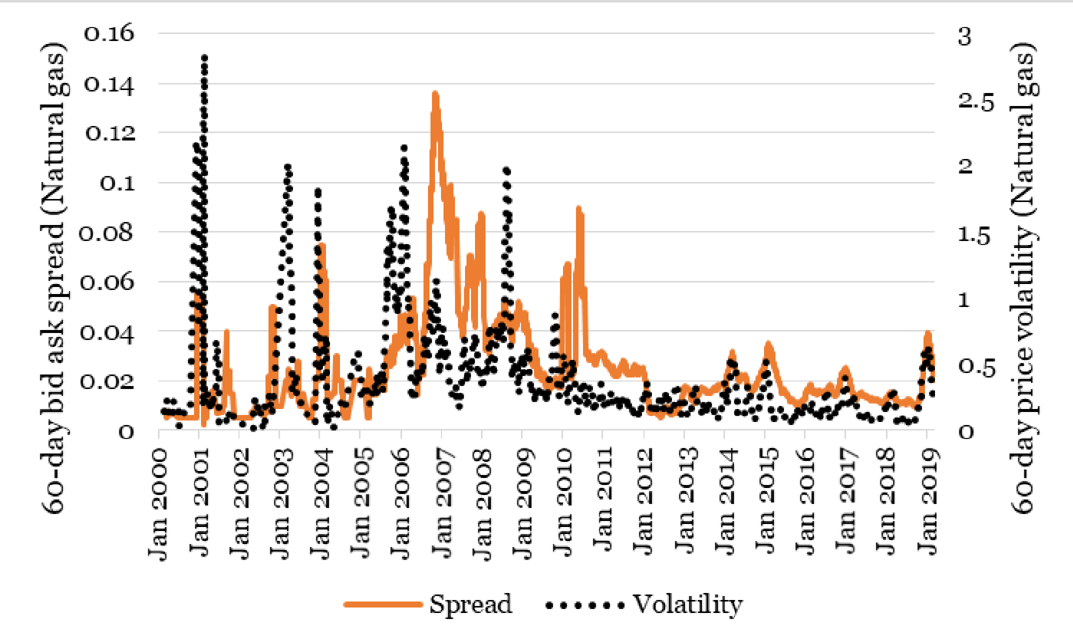


Source: Bloomberg; CEG analysis

3.3.2.7 Natural gas

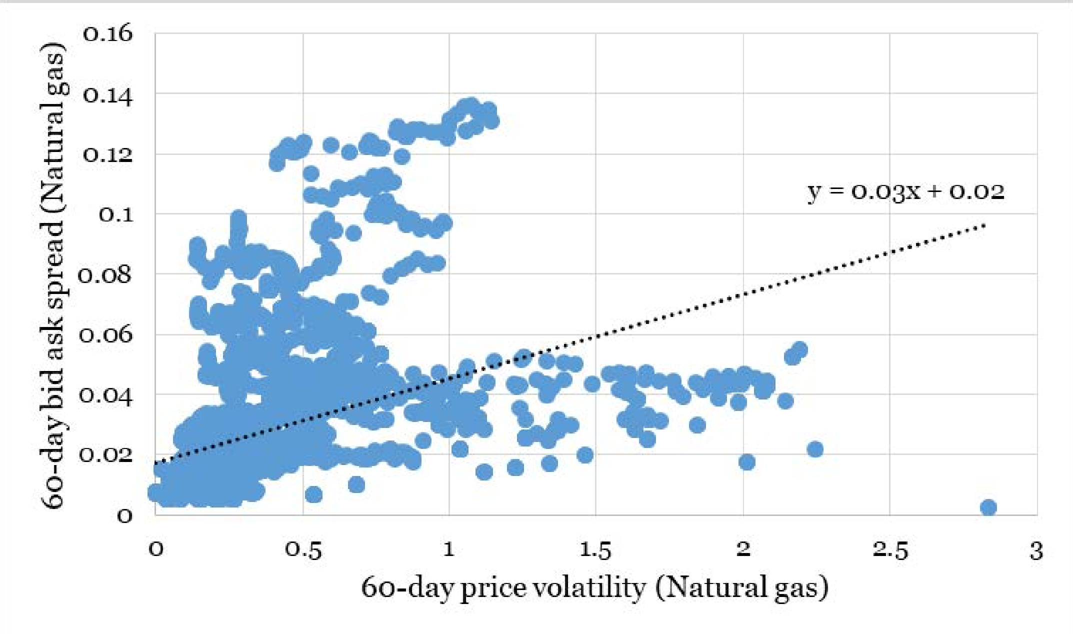
70. The BAS and price volatility time series for natural gas are shown in Figure 3-13, while the corresponding scatterplot is shown in Figure 3-14. The time series plot and the scatterplot show a positive relationship between BAS and price volatility. The correlation between the two series is **0.43**.

Figure 3-13: Time series of BAS and price volatility (natural gas)



Source: Bloomberg; CEG analysis

Figure 3-14: Scatterplot of BAS against price volatility (natural gas)



Source: Bloomberg; CEG analysis

4 Case study: UK energy market

71. In this section we carry out a case study of the UK energy market. We first trace the origin and ongoing development of Ofgem's market making rules, and then carry out a comparison of price volatilities in the UK and New Zealand wholesale energy markets in order to determine the appropriateness of enforcing a similar market making framework in New Zealand.

4.1 Ofgem market making rules

4.1.1 Origin of market making rules

72. On 12 June 2013, Ofgem published its final proposal pertaining to liquidity in the wholesale power market.[21] The final proposal included a 'Secure and Promote' licence condition, which was aimed at addressing the poor liquidity in the wholesale electricity market, which Ofgem perceived as a barrier to effective competition at that time [emphasis added]:

> *Ofgem is concerned that poor liquidity in the wholesale electricity market is posing a barrier to effective competition, thereby preventing consumers from fully realising the benefits of competition. While we have seen some recent improvements, particularly in near-term markets, this progress has been insufficient.* ***We therefore intend to intervene in the market to improve liquidity.***

73. One of Ofgem's proposals involves implementing a market making obligation (MMO), which Ofgem believed would achieve the objective of achieving robust reference prices. The MMO is summarised in Figure 4-1, which reproduces Figure 9 from Ofgem's final proposal. These market making obligations would initially apply to the big six suppliers, all of which were gentailers with substantial generation assets:[22]

> *Between them, the big six suppliers (British Gas Centrica, EDF Energy, E.ON, RWE Npower, Scottish Power and SSE) have a 98 per cent share of the household gas and electricity markets. It is harder for smaller, independent suppliers to compete against them as they do not have large power stations of their own. Unlike the big six suppliers and large independent generators, independent suppliers are reliant on buying*

[21] Ofgem, Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition, June 2013.

[22] Ofgem, Making it easier for independent suppliers and generators to compete, Factsheet 120, June 2013.

electricity from the larger market players. This means that their growth depends on the ability to trade with the larger suppliers.

Figure 4-1: Ofgem's market making obligations

<table>
<tr><th colspan="2">Figure 9: Market Making Obligation – detailed rules</th></tr>
<tr><td>B1 – Nominating a third party</td><td>Licensee may nominate a third party to undertake their obligation on the same basis set out in this licence condition (unless otherwise specified). The licensee must not nominate any party delivering more than one other licensee's obligation. The third party must be set up to trade with 10 generation and/or supply licensees.</td></tr>
<tr><td>B2 – Platform</td><td>The licensee is required to market make on any GB wholesale electricity market trading platform which can be accessed by a significant number (eg 10) of generation and/or supply licensees</td></tr>
<tr><td>B3 – Products</td><td>The licensee must post bids and offer prices in the following products:
Baseload: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3, Season+4
Peak: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3.</td></tr>
<tr><td>B4 – Availability</td><td>For each of the listed products the licensee must post prices within the bid-offer spread limits specified for more than 50 per cent of the market opening time in any given calendar month.
If a third party meets the obligation of two firms: the third party must post prices within the bid-offer spread limits specified for more than 80 per cent of the market opening time in any given calendar month.</td></tr>
<tr><td>B5 – Bid-offer spreads</td><td>When market making, the licensee must maintain a spread between their bid and offer price narrower than:
<table>
<tr><th colspan="2">Baseload</th><th colspan="2">Peak</th></tr>
<tr><td>Month+1
Month+2
Quarter+1
Season+1
Season+2</td><td>0.3%</td><td>Month+1
Month+2
Quarter+1
Season+1
Season+2</td><td>0.7%</td></tr>
<tr><td>Season+3
Season+4</td><td>0.5%</td><td>Season+3</td><td>1%</td></tr>
</table></td></tr>
<tr><td>B6 – Obligation to trade</td><td>Providing normal prerequisites are in place (eg a GTMA and credit agreement), if requested, the licensee must trade at posted prices.</td></tr>
<tr><td>B7 – Trade size</td><td>At any particular posted bid or offer price, licensee must be willing to trade in clip sizes of 5MW. The maximum trade size the licensee must execute is 10MW, although they may trade larger volumes if they wish.
If a third party is nominated to meet the obligation of two licensees: the maximum trade size multiplies accordingly.</td></tr>
</table>

Source: Ofgem

74. As can be seen in Figure 4-1, Ofgem included an important limit in clause B4, which states that the market maker must post prices within the bid-offer spread limits set out in clause B5 at least 50% of the time. It was envisioned that requiring obligations to be carried out only 50% of the time would avoid pushing excessive risk onto market makers [emphasis added]:[23]

At certain times, the risks associated with market making are increased. For example, when the market is especially volatile it becomes difficult to take a view on the price and post bids and offers to reflect this view. In this scenario, ***the market maker is at risk of having to trade at a price significantly different from the true market price and is therefore exposed to trading at a loss****. To help licensees manage this risk, it is appropriate to give them the opportunity to withdraw from market making at times. The availability requirement we have proposed – 50 per cent over the course of a month – is lower than that set out in most commercial agreements. This reflects the mandatory (rather than*

[23] Ofgem, Wholesale power market liquidity: final proposals for a 'Secure and Promote' licence condition, June 2013, p. 32.

voluntary) nature of the market making we are proposing. We believe that this requirement ensures regular opportunities to trade while allowing the market maker to manage their risks appropriately.

75. The obligation to engage in market making 50% of the time was later modified to two one-hour long windows daily:[24]

Our June 2013 consultation set out an availability requirement for market makers of 50 per cent of trading hours, calculated over the course of each month. We are now changing this to a requirement to market make during two hour-long windows each day.

76. The actual market making licence conditions are published under Special Condition AA Schedule B, which include conditions such as:[25]

- Availability of prices, clause 6(b): Where a bid or offer posted by the licensee for a particular Product is accepted, the licensee must post a new bid and offer for the Product within five minutes after the acceptance of the first bid or offer.
- Suspension of obligation, clause 7(a): If, at any time in a trading window, a Product has been traded at a price which is more than 1.04 or less than 0.96 times the price at which the Product was first traded within that trading window, the licensee may decide to cease posting bids and offers for that Product for the remainder of that trading window.
- Volume Cap, clause 10(a): If at any time in a trading window the difference between the licensee's traded bid volume and traded offer volume in respect of a Product equals or exceeds 30MW, the licensee may decide to cease posting bids and offers for that Product for the remainder of that trading window.

77. Ofgem also released additional guidance on Special Condition AA in order to clarify its interpretation of some of the conditions.[26]

24 Ofgem, Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition, November 2013, p. 19.

25 *Electricity Act* 1989 s 11A(1)(a): Modification of the licences of licensees specified in Schedule 1 who hold an electricity generation licence granted or treated as granted under section 6(1)(a) of the *Electricity Act 1989*.

26 Ofgem, Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance, January 2014.

4.1.2 Market makers incurred higher losses than expected during periods of high pricing volatility

78. In December 2017, Ofgem held a consultation to review the Secure and Promote policy, particularly the special licence condition.[27] The consultation uncovered a number of issues with the MMO conditions.

79. First, Ofgem stated at [2.4] that there was an acceptable level of liquidity within market making windows and for mandated products, but this was associated with a worsening of liquidity outside the windows. Ofgem noted that the market making obligations had inadvertently drawn all market activity into the market making windows.

80. Second, Ofgem admitted in [2.7]-[2.10] that it had severely underestimated the burden that the market making obligations imposed on obligated parties, particularly during periods of high volatility such as in 2016:

> *At the time of our original impact assessment, we estimated that the ongoing costs of complying with MMO would be around £1.6m per licensee per year. For the majority of years in Table 1, the actual costs faced by some licensees have been below this estimate. However, the costs reported by licensees during 2016 far exceeded our original estimates.*

81. Table 4-1 reproduces Table 1 of Ofgem's December 2017 consultation, which shows the market making cost information provided by the licensees. There was a spike in costs for 2016 due to high volatility over the last two quarters of that year, with costs around 10 times the levels observed in other years:

> ***When prices move significantly and rapidly, market makers often have their bids or offers aggressed and then pay a premium to reverse those positions once prices have moved in an unfavourable direction.*** *We were also told that this effect can be most pronounced at the start of market making windows where the narrow bid-offer spreads make price discovery difficult and prices can move very quickly.*

[27] Ofgem, Secure and Promote review: Consultation on changes to the special licence condition, December 2017.

Table 4-1: Market making costs incurred by licensees

Table 1 – fixed and variable costs per licensee (£m)

	costs provided by licensees (£m)			
	2014	*2015*	*2016*	*H1 2017*
Fixed costs	~ 0.5	~ 0.5	~ 0.5	~ 0.5
Variable	0.2 – 0.7	~ 0.5	3.0 – 8.0	0.3 – 0.7

Source: licensees

Source: Ofgem

82. Based on its December 2017 consultation, Ofgem elected to retain the MMO framework, but decided to make changes to the licence conditions in order to ameliorate the costs incurred by market makers during periods of high volatility. The proposed changes have so far not been implemented, because the entire future of the arrangements are in doubt (Ofgem is currently investigating policy options and alternatives to the MMO for promoting market liquidity).

4.1.3 Reduction in the number of market makers due to gentailers divesting their generation assets

83. There have since been a number of changes to the structure of the energy sector in the UK. In particular, some of the big six gentailers have divested a substantial portion of their generation assets before applying to be freed of their market making obligations. These divestments have successively reduced the number of obligated market makers to three.

84. Following one such divestment by Centrica Group that reduced the number of market makers to four, Ofgem released an open letter in August 2018 that indicated its awareness about the problems with the market making obligations:[28]

> *The recent divestment by Centrica, and our subsequent decision to remove the MMO from their licence, has caused us to reflect upon the fundamentals of the provision and its future application. It may, for example, mean that the changes proposed in December 2017 have been superseded by more important questions regarding the design of the MMO. Moreover, it is possible that the reduced number of parties subject to the MMO may affect the efficacy of the MMO in meeting its original objectives and/or may result in an undue burden being placed on the remaining obligated parties.*

[28] Ofgem, Open letter, 9 August 2018, p. 2.

In addition, market and business structures have evolved since the policy was initially introduced. ***While the current criteria used for selecting obligated licensees initially captured the six largest vertically integrated suppliers dominant at the time, two of these companies have now divested much of their generation portfolios.*** *Meanwhile, others are taking steps towards consolidation and amalgamation and there is a growing number of smaller scale suppliers active in the market.*

In light of these developments, we intend to review the MMO criteria and other potential mechanisms for delivering market making. ***We are also considering whether – as a result of the changes and prospective changes in market conditions – the remaining obligated parties will face disproportionate costs and risks in continuing to meet the licence condition, and whether on balance there is a case for suspending the MMO pending completion of our review.*** *This is in particular because the review is only likely to conclude during 2019.*

85. ScottishPower subsequently divested some of its generation assets and requested to be set free from its obligations under Special Condition AA, including its market making obligation under Schedule B.[29] Ofgem approved the request on the basis that ScottishPower no longer had simultaneous substantial presence in both the generation and domestic supply markets, due to the reduction in its generation market share.

86. In the meantime, Ofgem continues to keep track of the Market Making Obligation, in light of the declining number of market makers:[30]

As above, we think that the Secure and Promote licence condition is yet to fully meet its objectives. ***Without ScottishPower, there would be three remaining parties with the Market Making Obligation. The robustness of the reference prices available and the overall effectiveness of the intervention may fall with a smaller number of market-makers. However, at this stage we do not have clear evidence to suggest that three obligated parties will be significantly less effective than four.*** *We will continue to monitor and assess the effectiveness of the Market Making Obligation and the costs and risks to obligated parties in light of market developments. Alongside*

29 Ofgem, Request for modification of Special Condition AA of Electricity Generation Licences held by the ScottishPower corporate group, 31 January 2019.

30 Ofgem, Request for modification of Special Condition AA of Electricity Generation Licences held by the ScottishPower corporate group, 31 January 2019, p. 5.

this, we will investigate potential options and alternatives to the Market Making Obligation to support liquidity.

87. The fate of MMO currently hangs in the balance, with costs to market makers continuing to increase due to the smaller number of market makers.[31]

4.2 Comparison of price volatility in UK and NZ wholesale energy markets

88. Ofgem's experience in the UK shows that pricing volatility is a major positive driver of the costs associated with market making, with costs in 2016 rising to around 10 times of that observed in other years. We therefore now carry out an empirical comparison of volatility in wholesale energy prices and in the prices of wholesale energy futures for UK and New Zealand.

89. Unlike our analysis in section 3.3, we use the coefficient of variation as our measure of pricing volatility, since this measure is unit-less and can be used to measure the relative volatilities of assets denominated under different units.[32] The standard deviation measure that we used in section 3.3 will generate estimates that are not directly comparable since one will be denominated in GBP while the other will be denominated in NZD. In contrast, the coefficient of variation measure that we use here is unit-free and can be directly compared.

90. The coefficient of variation in this section is calculated over 60-day rolling windows. That is, at each date, we take the standard deviation of prices over the last 60 calendar days and divided it by the mean of prices over the last 60 calendar days.

4.2.1 Wholesale energy prices

91. We obtain daily wholesale energy prices from the following sources:[33]

- New Zealand: NZ Electricity Authority; and
- UK: Nord Pool Group (largest energy market operator in Europe).

92. We use the wholesale energy price across the whole of New Zealand as reported by the EA, and use the "base" block auction price reported by Nord Pool Group.

31 Platts, Outlook 2019: UK power sector's Market Making Obligation remains in balance, December 2018. Available at: https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/121918-outlook-2019-uk-power-sectors-market-making-obligation-remains-in-balance

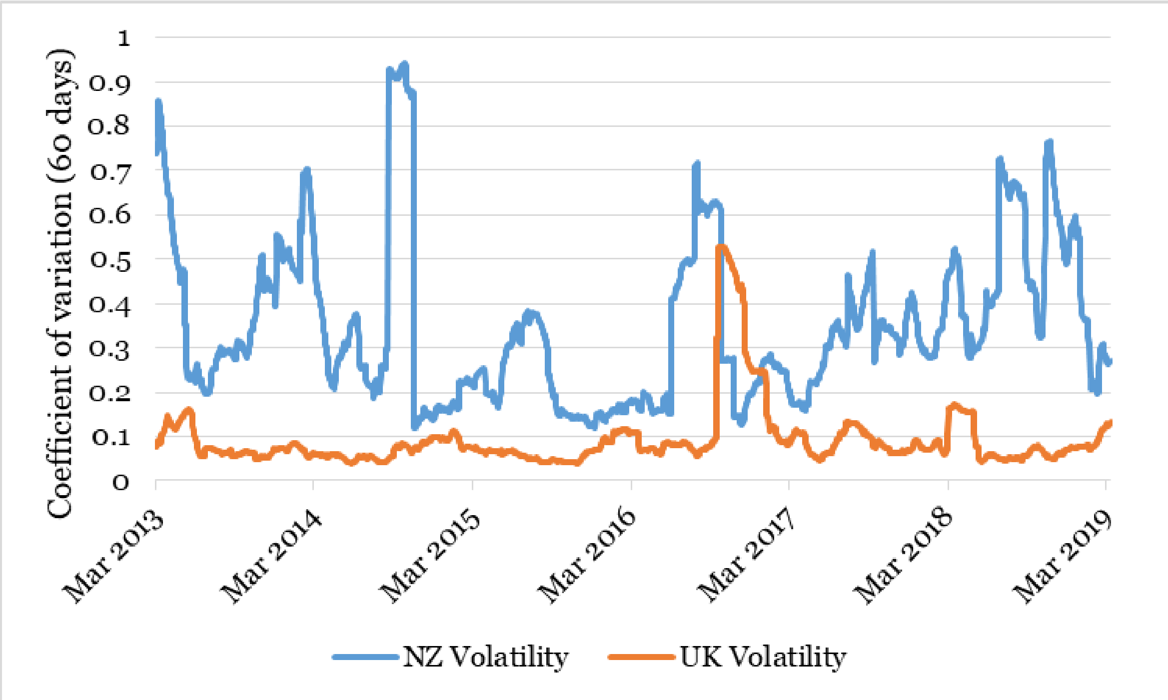
32 The coefficient of variation is equal to the standard deviation divided by the mean.

33 New Zealand data available at: https://www.emi.ea.govt.nz/Wholesale/Reports/W_P_C; UK data available at: https://www.nordpoolgroup.com/historical-market-data/

93. Figure 4-2 shows the time series plots of 60-day coefficients of variation for the UK and New Zealand wholesale energy prices. We observe that wholesale energy prices in New Zealand are almost always considerably more volatile than the corresponding prices in the UK. The exception is in the second half of 2016, where there was a notable spike in pricing volatility in the UK, consistent with Ofgem's observations in section 4.1.

94. Furthermore, the volatility series for New Zealand prices is itself very volatile, meaning that the market can oscillate between periods of high and low volatility very quickly. This is in contrast to the volatility series for UK prices, where the series does not switch between periods of high and low volatility as quickly.

Figure 4-2: Coefficient of variation in UK and NZ wholesale energy prices



Source: EMI, Nord Pool, CEG analysis

4.2.2 Wholesale energy futures

95. We obtain the following energy futures data from Bloomberg, where 'xxx' refers to future-specific Bloomberg ticker entries:

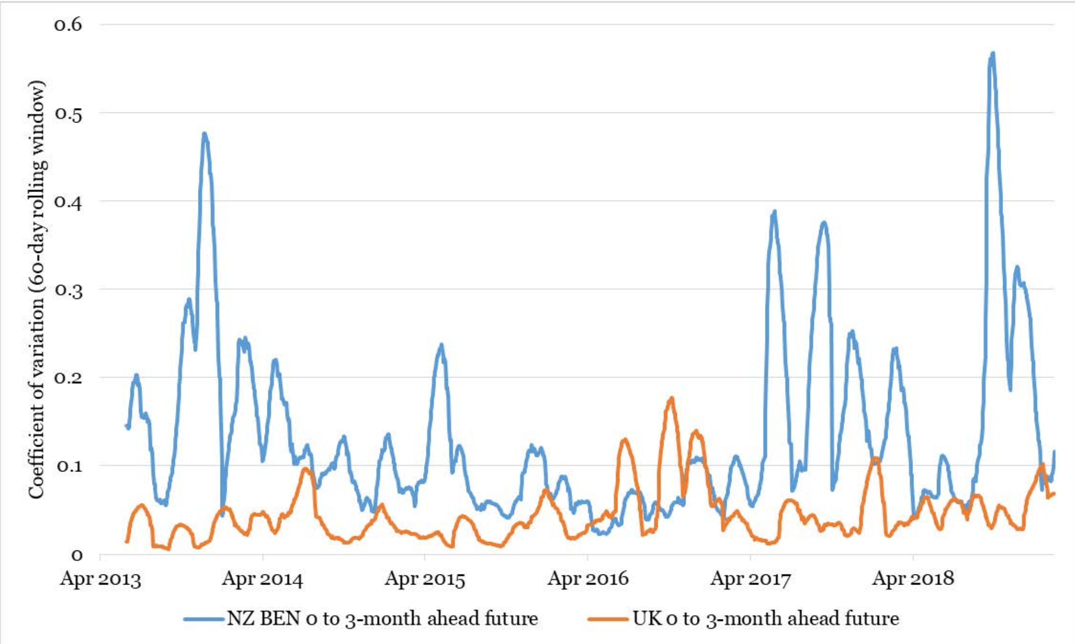
- New Zealand: BEExxx Comdty – Quarterly BEE base electricity future;[34] and
- UK: IQBxxx Comdty – Quarterly ICE UK base energy future.

[34] We also collected base electricity futures data for the New Zealand OTH node, and arrived at the same conclusions as with the BEE node.

96. We next combine the futures to produce two time series – one for New Zealand and one for UK. Our method for combining the futures involves taking the price of the instrument with the shortest residual maturity at each particular date. Since the futures that we obtain are quarterly instruments, this means that each observation in the series is taken from a future with residual maturity of between 0 and 3 months. Finally, we compute the coefficients of variation for the two time series over 60-day rolling windows.

97. Figure 4-3 shows the 60-day coefficients of variation for the prices of the UK and New combined futures. Consistent with our findings for wholesale energy prices in section 4.2.1, we find that the New Zealand series has historically shown a higher coefficient of variation than the UK series on average, and that the coefficient of variation for the New Zealand series has itself also been considerably more volatile.

Figure 4-3: 60-day coefficient of variation (0 to 3 months ahead futures)



Source: Bloomberg, CEG analysis

98. We also generate alternative time series based on 3-month, 6-month, and 9-month, ahead futures. As an example, the 6-month ahead future series for the following date would be calculated in the following way:

- For 28 June 2013, the selected instrument must mature later than 28 December 2013. We therefore use the Jan 2014 future for UK, and the March 2014 future for New Zealand; and

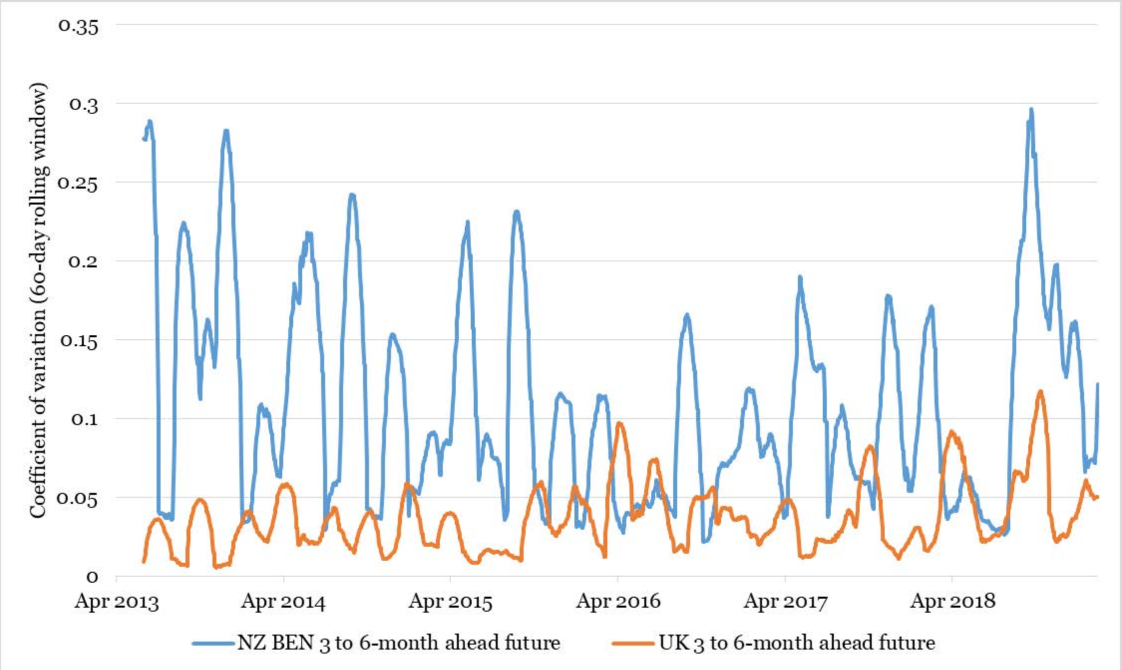
- For 1 Jul 2013, the selected instrument must mature later than 1 Jan 2014. We therefore use the April 2014 instrument for UK, while continuing to use the March 2014 instrument for New Zealand.

99. The residual maturities at each date for the above series would therefore be:

- 3-month ahead series: 3-to-6 month residual maturity; and
- 6-month ahead series: 6-to-9 month residual maturity.

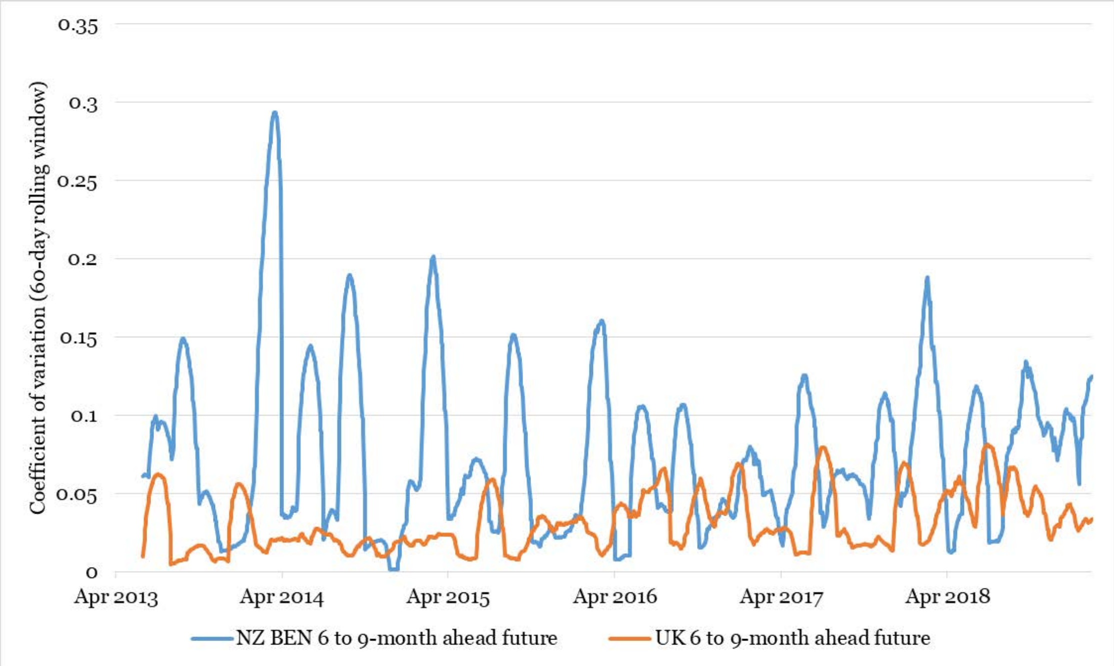
100. The 60-day coefficients of variation for the alternative series are shown in Figure 4-4 to Figure 4-5. We make the same observations as with Figure 4-3, in that the New Zealand series has historically shown a higher coefficient of variation than the UK series on average, while itself being considerably more volatile.

Figure 4-4: 60-day coefficient of variation (3 to 6 months ahead futures)



Source: Bloomberg, CEG analysis

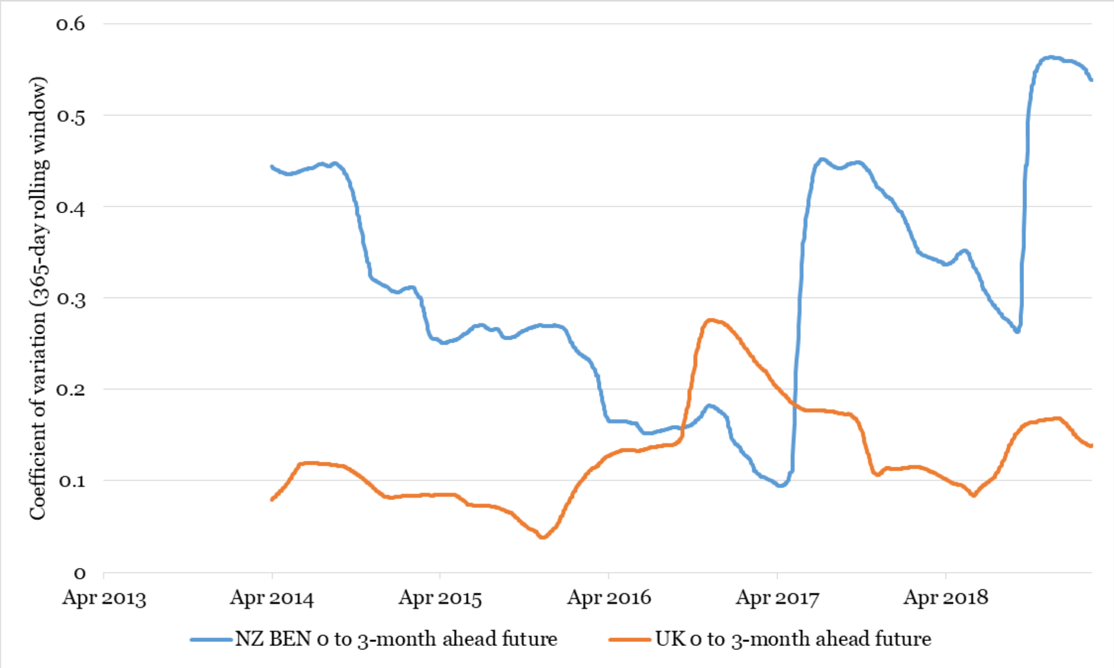
Figure 4-5: 60-day coefficient of variation (6 to 9 months ahead futures)



Source: Bloomberg, CEG analysis

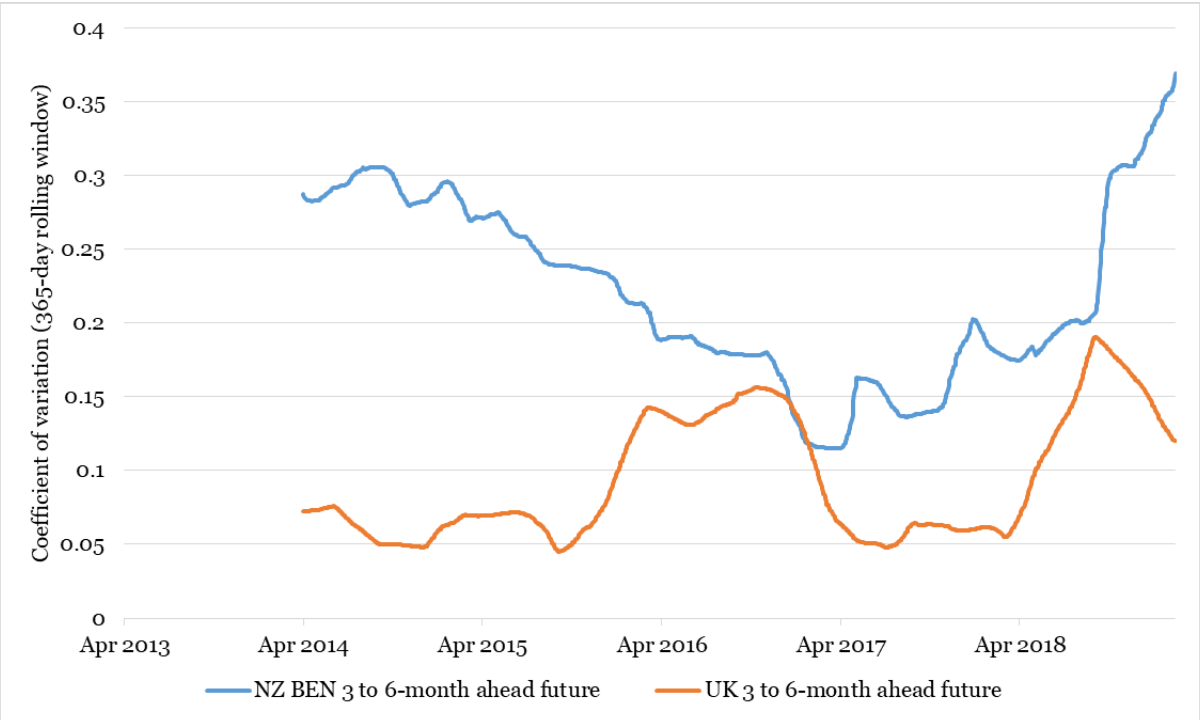
101. Finally, we also compute the 365-day coefficients of variation for the NZ and UK electricity futures. These are shown in Figure 4-6 to Figure 4-8, for which we arrive at the same conclusion that the New Zealand series has historically shown a higher coefficient of variation than the UK series on average, while itself being considerably more volatile.

Figure 4-6: 365-day coefficient of variation (0 to 3 months ahead futures)



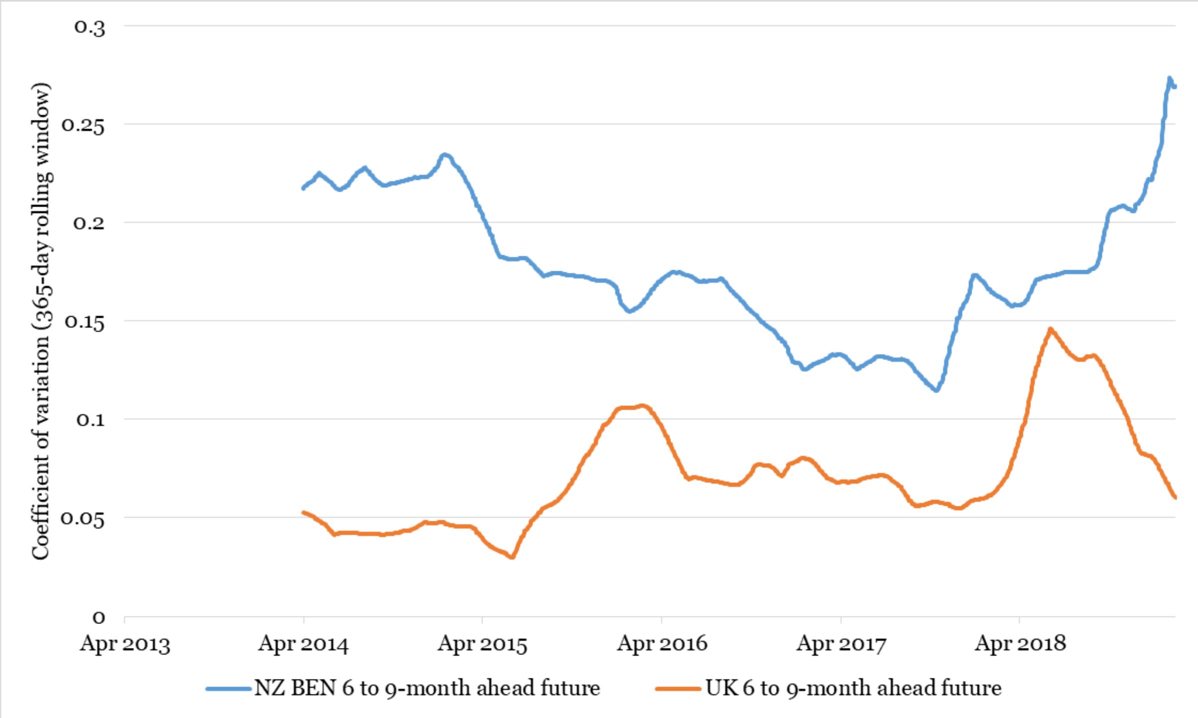
Source: Bloomberg, CEG analysis

Figure 4-7: 365-day coefficient of variation (3 to 6 months ahead futures)



Source: Bloomberg, CEG analysis

Figure 4-8: 365-day coefficient of variation (6 to 9 months ahead futures)



Source: Bloomberg, CEG analysis

4.3 Summary

102. The UK energy market presents a highly relevant case study, in that Ofgem had earlier identified liquidity issues in the wholesale market and decided to intervene by imposing market making obligations on the big 6 suppliers, using similar lines of reasoning to that of the Electricity Price Review Panel.

103. Overall, the UK's experience showed that the market making obligations were a lot more costly than anticipated, with market makers incurring very high costs during periods of high price volatility. The market making obligations also had the unintended effect of drawing most energy trading into the market making windows, thereby worsening liquidity outside of those windows.

104. In addition, the recent divestments of generator assets by UK gentailers has led to a reduction in the number of market makers from 6 to 3, and it is anticipated that the costs that are likely to be incurred by the remaining market makers is likely to continue to increase.

105. Ofgem has so far responded by proposing some changes to the licence conditions, such as a loosening of obligations in periods of increased volatility. However,Ofgem has also stated that it will continue to "investigate potential options and alternatives to the Market Making Obligation to support liquidity".

106. Our analysis of pricing volatility in wholesale energy prices and futures in the UK and New Zealand wholesale markets suggests that the New Zealand wholesale market is more volatile than that of the UK. Given this result, it appears likely that imposing similar market making obligations on New Zealand gentailers is likely to result in significantly higher costs that will have the effect of pushing excessive risk away from other market participants and onto the gentailers.