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Electricity Authority

By email to: policyconsult@ea.govt.nz

Tēnā koe

Submission on evolving multiple retailing and switching

Thank you for the opportunity to provide a submission on the consultation paper "Evolving Multiple Retailing and Switching" (the consultation paper).

We support a number of the proposals in this paper to improve customer mobility, particularly those that enhance consumer switching.

However, we consider that it is important that the Authority ensure that its proposals are a net benefit to consumers and any proposed solutions and technical framework is suitably thought through. This is particularly important for the multiple trading relationships (MTR) proposal. Proving the customer appetite, market appetite for discrete injection products, and consumer benefit will be crucial to justify the substantial scale and cost of this change.

Part 1 - Multiple Trading Relationships

We expect that when the Authority carries out its statutory obligation to undertake a full cost-benefit assessment of MTR,[1] it will likely show that the benefits are greatest for commercial and industrial (C&I) customers. This view is supported by the approach in Australia that has started their MTR journey with C&I businesses.

For C&I customers, we consider that retail electricity supply is often a distinctly different service to services controlling flexible load. Most C&I customers also have a mix of controllable and non-controllable assets, that can easily be identified and controlled separately, making it ideal for an MTR model. The costs of setting up this arrangement can be contained to the customer and flexibility provider, and not impose wider costs on the industry.

There is also appetite for MTR offerings from the market. Contact's Simply Energy team are interested in both MTR type 2 "Separate traders for each consumption meter channel" and ultimately MTR Type 3 "Separate retailers for designated appliances" which we believe is similar to the establishment of "Secondary settlement points" in the NEM. MTR type 2 "Separate traders for each consumption meter channel" is a step in that direction. If option 1 is pursued by the Authority following this consultation, the focus should be on building out the systems to facilitate Option 2 as well, as we do not believe this is materially more complex or costly.

We are already seeing "MTR" in action for process heat decarbonisation. Where a C&I site has been provided a separate ICP for the new electric boiler, there are examples where the ICP to the main plant

[1] We note that the Authority asserts at para 8.13 that it expects that the benefits will outweigh the costs. However, no attempt at quantification has been made, and it is noted that the costs cannot be quantified at this point. The benefits listed are also highly speculative and not supported by any evidence. We do not consider that this has met the requirement on the Authority under s39(2)(b) of the Electricity Industry Act 2010.

and the ICP to the new and flexible asset, are with different retailers and/or on very different retail products. This has been able to be progressed because they happened to have separate ICPs for their assets. Expanding MTR to facilitate this where it does not make sense to have two separate ICPs at a site will help this type of arrangement occur at more sites.

The benefits of MTR for mass market customers are less clear, and the costs are higher

We are less supportive of the proposed approach to mass market MTR and consider it unlikely it would pass a rigorous cost benefit analysis in its current form.

Contact has substantial experience in developing new and often innovative products and services, including our 'Good' plans, Hot Water Sorter, entry into broadband and mobile telecommunications. When we look into these products and services, we utilise global best practice by taking an incremental delivery approach to ensure we can develop products and services with a customer first mindset and balancing deliver cost and speed to market. This includes:

1. Customer testing through research, customer testing and leveraging insights to ensure we are solving a customer need for the new product or service. During this process we leverage international research, qualitative and quantitative customer research, user testing with prototypes, etc
2. With incremental delivery we often 'go live' with a 'minimum viable product' (MVP) to test our assumptions about the customer needs and experience are correct. Delivering in this way is critical to ensure we can adapt to insights and learnings fast and early. During this stage we aim to keep costs low and will accept a certain degree of manual processing in the background to get a product off the ground. If we haven't met our defined pilot objectives during the period, we will either adapt the solution or not progress the product further.
3. A scaling up stage where we build in the necessary system changes to set us up for long term success. We only enter this stage when we know the new offering is already successful, so we know we are investing in the right things.

We consider it important that the Authority follows a similar discipline to not impose unnecessary costs on the sector and ultimately consumers. Currently the benefits identified by the Authority are highly speculative and not supported by evidence. We do not consider that this meets even the first market research stage of good product development.

The Authority rightly notes that it cannot quantify the costs at this stage. We consider that the costs of the proposed approach are substantial and varied, including:

- The direct costs of implementing the changes. These are addressed in more detail below, but we approximate they will cost us around $3m across our Contact and Simply Energy environments.
- The barriers to entry that this additional complexity will create. As noted by Dr Stephen Littlechild about the rush of retail regulations in the UK from 2008-2014, such interventions can have adverse consequences for competition.
- These requirements will also tie up product development resource across the industry. Stalling market led innovations that may take a more robust approach to understanding consumer needs than has been demonstrated by the Authority in this consultation paper.

We therefore recommend that the Authority takes the following steps:

1. Commission an independent and thorough market research project of a scale reflective of the material costs that the regime would impose on consumers. This should consider both the customer appetite but also provide a realistic assessment of the likelihood that market participants will be willing to offer a standalone injection products at scale.

2. If the market research supports the Authority's preconceptions, then move on to a minimum viable product stage, where the costs to enable MTR sit with the parties offering or benefiting from those services. This may take features from the proposed Options 2 and 3 in the consultation paper, but we consider that more product development is required together with technical and industry expertise.

3. If the minimum viable product shows strong customer appetite to justify a wide roll out then move on to the more expensive system-level change proposed in Option 1.

Part 2 - Switching changes

Contact is largely supportive of the proposed switching changes. We can see value to participants and customers for the majority of these changes.

There are some changes that we still consider unnecessary or that will drive cost for no real benefit. E.g. broad timestamping requirements, meter reading decimal places & MEP nomination process changes to name a few. We also recommend the proposals with less clear value are only implemented where other changes are already occurring within a related function, process or interface.

Part 3 - Implementation timeframes

We consider that the proposed 18 month implementation timeframe to be a reasonable starting position. However, this will depend on the complexity and scale of the requirements in the final decision. We support the Authority taking a staged approach to implementation, however the changes must also be logically grouped. Staging is only sensible where the changes are grouped into aligned components/functions. It makes more sense to deal with an entire industry process or interface once, even if it takes a bit longer.

We recommend that any registry and market system changes that require participant system integration/change is implemented in a single ~18 month program of work. Any administrative or procedural related Code changes could be done before this begins.

As above, we also consider that more time needs to be allowed to follow best practice product development practices. This must include a design phase for the minimum viable product stage, which must involve technical, market, and consumer input. The current set of options are not yet at the required standard to be rolled out after proper market research.

Finally, we would also like to highlight that this is only one of many EA programs of work underway or on the near horizon which often results in prioritisation and shared resource competing against itself. For example, the Retail data project, Consumer data rights, digitalisation and more. We have significant concerns that the volume of regulated project work will consume extensive resource for the next 2+ years and potentially stifle capacity for product design and innovation based initiatives, unless efficient and fit for purpose solutions are considered.

Ngā Mihi

[redacted]

Brett Woods

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Contact Energy.

#	Question	Response
		Section 2 – Issues summary
Q1	Do you agree that multiple trading relationships and improved switching are key components of consumer mobility? If not, what would you change and why?	Somewhat – we agree with the concept of consumer mobility, however don't consider the likely current or near future service provider or customer demand warrants the level of change being proposed and resulting cost to participants. We are also unsure of the logic of jumping to mass market MTR as the necessary solution. This must be supported by more market research to support the Authorities presumptions.
Q2	Do you have any comments regarding future stages of multiple trading, whether the proposal provides optionality for the potential future stages, and the options the Authority should consider?	Simply Energy see long term value in building out MTR processes to enable Type 3 MTR for C&I customers and as per our submission to the 2D workstream "Rewarding industrial demand flexibility', we believe this should be actively explored. Otherwise, our feedback is similar to Q1 above in the mass market setting, we consider a staged approach to be sensible, however the preferred solution and cost benefit analysis for stage 1 is significantly unproven, let alone any future stages. A fit for purpose/minimum viable change approach needs to be implemented for stage 1 to inform a comprehensive CBA for any future stages.
		Section 3 – Part 1 MTR Proposed Changes
Q3	Do you agree with the proposed solution? If not, what would you change and why?	Contact is supportive of the industry exploring options to enable more than one retailer at an ICP, where there is a confirmed supply (service provider interest) and customers signalling interest these services. As outlined in our introduction, we do not agree with investing millions of dollars to enable MTR services without an appropriate level of research and analysis to support this. We consider the preferred/proposed solution for stage 1 to be over engineered, too broad and extremely costly. With this in mind, Contact strongly opposes the preferred solution (Option 1) on the basis that this imposes significant costs on the entire industry for a unproven CBA and uncertain service uptake. Our view is that option 2 would be slightly better, however is still significantly complex and costly due to the changes needed in core metering and billing systems. We consider that the Authority must first undertake more thorough market research to understand the value of mass market MTR. If this supports the Authority's presumptions then it should move to a minimum viable product stage where the most cost effective, minimal impact and succinct option is designed. One way to achieve this may be to completely detach the MTR solution from the core existing switching process and have a standalone process and interface to manage the outlier changes. There are many ways to technically achieve this that would then enable each participant to make choices on how they design solutions (automated or manual) to manage costs. A tidier and lower impact/cost solution would be to have a separate and simple ICP level field/s or identifiers in the registry that records

		where a MTR arrangement is in place and the makeup of the arrangement. You could then have a separate or new switching process and interfaces to manage changes to this arrangement. This would be a targeted process that only results in changes/requirements where the MTR service is in place, rather than imposing changes to all ICP's and parties involved.
Q4	Do you agree with the benefits anticipated from the proposed solution? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	No, we consider the benefits of proposed/preferred solution to be significantly outweighed by the costs to implement. We strongly recommend an alternative, lower level of change solution to identify actual demand and uptake, to inform any future potential more extensive and comprehensive solutions and system changes.
Q5	Do you anticipate the proposed solution will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	The proposed solution will introduce significant costs. We have performed very high level scoping and change assessment which puts the total MTR cost between 2-3 million dollars for Contact. Simply Energy have indicated the total cost of the entire set of changes within this consultation to sit at ~1.2m. As we have commented on previously, the primary reason for the significant change cost is due to the fact existing switching and registry processes are being changed to facilitate the new MTR solution. This change will affect our core registry, switching, metering and billing systems. The anticipated effort associated with regression testing those systems will run into the hundreds of thousands of dollars alone (as you need to retest the existing standard registry and switching process as well as the new MTR requirements). Another reason to detach the MTR solution and functionality.
Q6	Do you agree with the advantages and disadvantages of options 2 and 3? If not, why not or how would you overcome the disadvantages?	Not entirely, in terms of option 2 – we agree that there is significant benefit and participant cost savings through avoiding changes where MTR won't apply (which may be the majority of customers). We also disagree with the disadvantages outlined in option 2. A detached solution would enable participants to choose how they design their internal systems and treat MTR related switches and processes (through automation or manually) which will significantly reduce implementation effort and costs. We agree with most of the views on option 3 and that it's far better to have visibility and some form of robust system based process to accommodate MTR, however believe there are better options to achieve this and manage change costs.
Q7	Do you agree that option 1 is the preferred option over options 2 and 3 and the reasons for preferring option 1? If not, why not?	Continuing our primary views, we do not consider any of the options outlined to be preferred. option 2 and 3 are slightly better compared to option 1, in terms of sensibly managing the extent of industry change and system costs. We consider there are better solutions to land in a middle ground. Whichever solution the industry lands on, it needs to be fit for purpose based on the known current and short term requirements. We consider the best solution is one where the market system service providers (Registry and reconciliation manager etc.) facilitate 90% of changes to enable MTR. Its far more cost effective

		to change 2 or 3 market systems than it is to change ~50+ participants systems.
Switching Process Changes		
Q8	Should the provision of the average daily consumption remain mandatory, or should it be optional? If optional, please explain why?	Mandatory. It is needed for any switches away within 30 days. Also, Traders use this to estimate when there are no reads received.
Q9	Do you agree with the proposal to align timeframes to a maximum of two business days for NT and AN notification and to reduce timeframes for the CS file?	We agree to a two-business-day timeframe for AN. However, maintaining consistency for the CS file across both MI and TR switches is equally important to minimise system costs and avoid confusion. We recommend a standard of two business days after the switch event date to ensure that the MEP has received actual data for AMI meter, and for non-AMI retailer is creating the estimate irrespective of the switch type. In cases involving a backdated switch date, we propose a timeframe of three business days from the receipt of the NT file.
Q10	Do you agree with the proposed solutions? If not, what would you change and why?	We have provided commentary/response on each of the individual sub level changes. Where no response has been provided it's safe to assume that we're in agreement with that particular change, with the overarching principle or consideration being that we shouldn't make changes where any value or benefit is neutral (unless we are changing other attributes/components of a process or function).
	d) Time stamp requirements	While we understand the future proofing angle of the timestamp change, we consider it would be far more cost efficient for the registry to perform timestamping itself. Otherwise, every participant is going to have to make a significant number of system and interface changes for no real benefit (as the registry could work this out themselves).
	e) Require losing trader to use gaining traders requested switch date	We largely agree with this, so long as the criteria for losing retailers changing the switch event date is clearly defined/outlined. The Gas Switching and Registry rules already have this requirement in place and would be a good starting point to enable alignment and change/cost efficiencies.
	f) Clarify that a gaining MEP may change a metering installation at an ICP prior to completion of an ICP switch.	Agreed, provided that the meter change date is on or after the switch event date. This ensures that no rework will be required by the losing retailer to correct any discrepancies caused by a meter change occurring prior to the switch event.
	j) Standardise switch event meter readings to be the actual read up to two decimal places.	In our assessment, the proposed measure is neither necessary nor does it offer any material benefit to retailers or the broader market. On the contrary, it would introduce additional costs. We have explored options to change decimal places within our systems off the back of previous participation audit recommendations, however the cost to change this core attribute and implement (~100k) far outweighed any benefit or market impact. We recommend truncating decimal points for switch readings rather than implementing decimal point precision. This alternative represents a minimal change for retailers, promotes alignment of readings across retailers, and does not require any modifications to the existing registry functionality/interfaces to retailer's systems.
	p) Require a trader to accept a switch withdrawal request within five business days of the switch withdrawal (NW file) date, but only under specified circumstances	Agreed, however this should be time-bound, within two months of the switch completion date? Beyond this period, any action should be discretionary. The gaining trader must ensure that the ICP status is reverted to its original state, when ICP was switched from the losing retailer, unless the losing retailer has explicitly agreed to an alternative arrangement.

	…	
Q11	Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	Any additional benefits or supporting content has been included in our individual proposed change level commentary.
Q12	Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	There will be costs associated with implementing the proposed switching changes. We're comfortable with these costs so long as the benefits exist and to ensure the industry processes are operating effectively and efficiently. We have not had sufficient time to assess or quantify the level of change and resulting cost outside of the MTR change assessment (Q5 response). We would still anticipate these changes will likely exceed the $500k mark from an end to end project cost position, across both Contact and Simply Energy
Q13	Are there any other files that should be added to this list?	
	MEP Switching	
Q14	Do you agree with the proposed solutions? If not, what would you change and why?	We have provided commentary/response on each sub level changes. Where no response has been provided it's safe to assume that we're in agreement with that particular change, with the overarching principle or consideration being that we shouldn't make changes where any value or benefit is neutral (unless we are changing other attributes/components of a process or function).
Q15	Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness and efficiency? Can you quantify these benefits?	We have provided commentary/response on each sub level changes. Where no response has been provided it's safe to assume that we're in agreement with that particular change, with the overarching principle or consideration being that we shouldn't make changes where any value or benefit is neutral (unless we are changing other attributes/components of a process or function).
	a) Allow both gaining and losing MEP to populate metering events for the same day (with time stamping).	We agree with allowing multiple metering events on the same event date, however once again consider that the registry would be the best place to capture these requirements, rather than imposing significant interface changes costs on all participants. If MEP's are required to populate removal dates and readings, that would enable the registry to determine which meter is installed where/when.
	b) Create new fields to identify specific meter types and communication capability/status.	Contact strongly agrees with this proposed change. The current Y/N AMI Communications flag does not provide enough indication to enable a retailer to perform robust prequalification checks for any products that are reliant on timely and frequent HHR data. We often encounter scenarios where we offer a customer a ToU product based on the AMI comms flag being Y, only for the data frequency to be insufficient or too infrequent which then results in the product offering being reversed. This is a poor outcome and experience for customers. We would consider an extended or more granular ICP level meter comms quality indicator to be satisfactory to provide better insight

		into the communication status of the entire site. We don't consider it necessary to change the metering channel structure as this would introduce more complexity and cost for no real benefit (as most retailers aren't geared up or there is little demand or benefit to providing different products at a meter level).
	h) Place obligations on traders to notify the registry manager of a MEP nomination, and on MEPs to accept the nomination on or before the date the metering is installed or decline the nomination if the metering cannot be installed. This would be supported by a registry enhancement to automatically decline unaccepted MEP nominations in specified timeframes, and a new obligation on traders and MEPs to include this requirement in the trader's and MEPs audits.	We still consider the overarching requirement to pre-nominate to be against the grain and intent of registry itself. I.e. the registry is a database of records and events that have occurred, not a workflow tool containing events that may or may not occur (as many MEP pre-nominations do not occur as reinforced by having to further develop auto decline functionality). Now would be the ideal time to remove the pre-nomination registry functionality and requirements and reinforce the existing Code requirements whereby retailers must already have arrangements with MEPs in place, to include any pre-nomination or metering provider allocation commercial requirements. The MEP pre-nomination process will likely continue to be an issue no matter how many band aids the industry apply to it. There are a large number of extensive metering deployment and programs of work underway where the MEP's preference is to receive a pre-nomination for large batches of ICP's, well into the future. Applying auto decline functionality based on a timeframe is only going to result in rework and additional administrative costs for retailers due to the fact that a large number of service orders can't be fulfilled for reasons outside of anyone's control (access, customer refusal, weather etc.). In summary, our preference would be to remove the MEP pre-nomination requirements and functionality from the registry altogether and cover this under the Code and MEP/retailer arrangements.
	(i)Require MEPs to populate new or amended registry metering events for ICPs for 75% within five business days of the metering installation being certified/modified, or from when the ICPs status changes to "active" and 100% within 10 business days. These percentages are to be calculated over any 12-month period. As some delays are outside the control of the metering equipment provider, provision for these delays will reduce compliance costs. For clarity, the MEP has control of the performance of their agents (eg contractors and technicians), and the certifying ATH through the terms of their	Disagree - this drives misalignment between participants Code requirements in relation to the time allowed to update registry information. I.e. MEP's and retailer registry update timeframes are different. There should be no reason these timeframes should be different across participants as we all largely have the same 'reasons outside our control' operational factors. Instead, there should be an overarching Part 11 Code consideration/clause to cater for technical non-compliances where it's impractical to meet 100% compliance. Having this would enable participants to focus on improving things within our control and provide clarity to auditors when assessing participants performance. The EA is likely in the best position to obtain registry data to determine what the appropriate threshold should be for timeliness of updates to the registry (it certainly shouldn't be 75% within 5 BD's as this sets the benchmark too low). We would assume the current benchmark would be closer to 90 or 95%with the remainder being the outliers/exceptions.

	arrangements. Compliance with this requirement will be included in the MEP's audit	
Q16	Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	There will be costs associated with implementing the proposed MEP switching changes. We're comfortable with most of the changes and costs, where we have signalled support of the change and we consider reasonable benefits to exist. There are some instances or changes that we're less supportive of or consider that the changes do not provide any benefit and create unnecessary cost (namely MEP pre-nominations process, broad timestamping requirements and misalignment between MEP and other participants registry update timeframes). We have not had sufficient time to assess or quantify the level of change and resulting cost outside of the MTR change assessment (Q5 response). We would still anticipate these changes will likely exceed the $200k mark from an end to end project cost position.
		Distributor Switching
Q17	Do you agree with the proposed solutions? If not, what would you change and why?	Overall, Contact supports the proposed concept of shifting the distributor switching workflow into the Electricity Registry, and the objectives for doing so. However, there are specific aspects of the proposal that raise some concerns. We are concerned about the treatment of retailer non-acceptance by a specified date being deemed as automatic acceptance. We believe that if no response is received by the deadline, a retrigger or reminder notification should be issued instead, as the lack of response is more likely to be unintentional. Imposing an automated acceptance response on a retailer that may have been inclined to reject the distributor switch will only further disrupt the process—impacting the consumer experience, data submissions, and overall compliance. We also feel that for these changes to be successful, there must be: • the ability for all parties to input and update information related to the distributor switch directly within the Registry, • an easy way for retailers to identify ICPs going through a distributor switch, prior to initiating a retailer switch, • additional reporting functionality to allow the monitoring of open distributor changes. We feel these changes will further enable participants to effectively manage this process without requiring extensive system changes and costs.
Q18	Do you agree with the benefits anticipated from the proposed solutions? Are there other benefits you can anticipate or improvements to operational effectiveness	Any additional benefits or supporting content has been included in our individual proposed change level commentary. While the proposed changes are welcome and a step in the right direction, there are still instances where some retailers are unable to, or it isn't feasible to supply new embedded networks. We believe further consideration is needed, including a defined outcome for situations where a retailer rejects a network transfer. Clarity is

	and efficiency? Can you quantify these benefits?	required on what should happen with the embedded network setup if the retailer is unable to engage consumers to switch prior to the go-live date, which would otherwise allow the distributor switch to proceed.
Q19	Do you anticipate the proposed solutions will introduce cost into your organisation, and if so, can you quantify this cost and/or provide a high-level description of the changes that need to be made?	Any additional costs associated with these changes will depend on whether the necessary Registry-related actions can be completed manually within the Registry itself, rather than requiring system changes to support the new workflow.
	Implementation timeframes	
Q20	Would you prefer a single implementation or a staged implementation? Please give reasons for your preference	As touched on in our intro, staged implementations make sense, however only where each stage is independent or focussed on a single process, interface or function. If each stage crosses over multiple functions, then its more logical and efficient to take a bit more time and implement via a single project structure and timeline. I.e. if Stage 1 of MTR requires switching changes, then it makes sense to implement the wider switching changes at the same time (don't open the same bonnet twice, at two different times as it creates additional project inefficiencies, resource overheads and change costs running two programs of work).
Q21	Do you agree with the suggested implementation timeframes? If not, please state your preferred timeframes and give reasons for your preference	The timeframes (18 months from final decision) look ok, however as per our intro commentary, this will be dependant on the final solution and complexity scale.
	Regulatory statement	
Q22	Do you agree with the objectives of the proposed amendments for MTR? If not, why not?	We agree with the intent and direction the EA are trying to take to accommodate MTR, however reiterating we do not believe the proposed options and solutions meet the objective under 8.5 (ensuring the lowest impact possible for participants…). The preferred solution is proposing to make changes to all existing switching and registry processes, which by design is the opposite of this objective (all participants are impacted across a significant number (nearly all) of existing interfaces and industry processes).
Q23	Do you agree with the objectives of the proposed amendments to improve switching processes? If not, why not?	Yes, once again with the disclaimer that changes are only made where there is a proven benefit case to offset costs, or other changes are being made at the same time where any benefit is considered more neutral.
Q24	Do you agree the benefits of the proposed amendment outweigh its costs?	We refer to our commentary throughout our response which outlines our position on any cost versus benefit of each individual section.
Q25	Do have any comments on the preferred and alternative options discussed in the 2019 Issues paper?	Our only comment is that is it sensible to ensure that anything outlined within the 2019 issues paper is still relevant and the historical cost benefit analysis is up to date and accurate, however consider this consultation process to be a good test of this.

Q26	Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	We refer to our commentary throughout our response which outlines our position on any proposed amendments or solutions versus alternative options.
Q27	Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	We refer to our commentary throughout our response which outlines our position on any related Act or statutory objectives
Q28	Do you have any comments on the drafting of the proposed amendment?	