Vector Limited
110 Carlton Gore Road
PO Box 99882
Newmarket
Auckland 1149
+64 9 978 7788 / vector.co.nz

9 February 2024

Electricity Authority
Level 7, AON Centre
1 Willis Street
Wellington

By email: policyconsult@ea.govt.nz

Code amendment omnibus two: December 2023 – Vector response to consultation paper

Vector appreciates the opportunity to provide comment on the Electricity Authority's (the Authority) Code amendment omnibus two: December 2023. This submission is not confidential and can be published in full on the Authority's website.

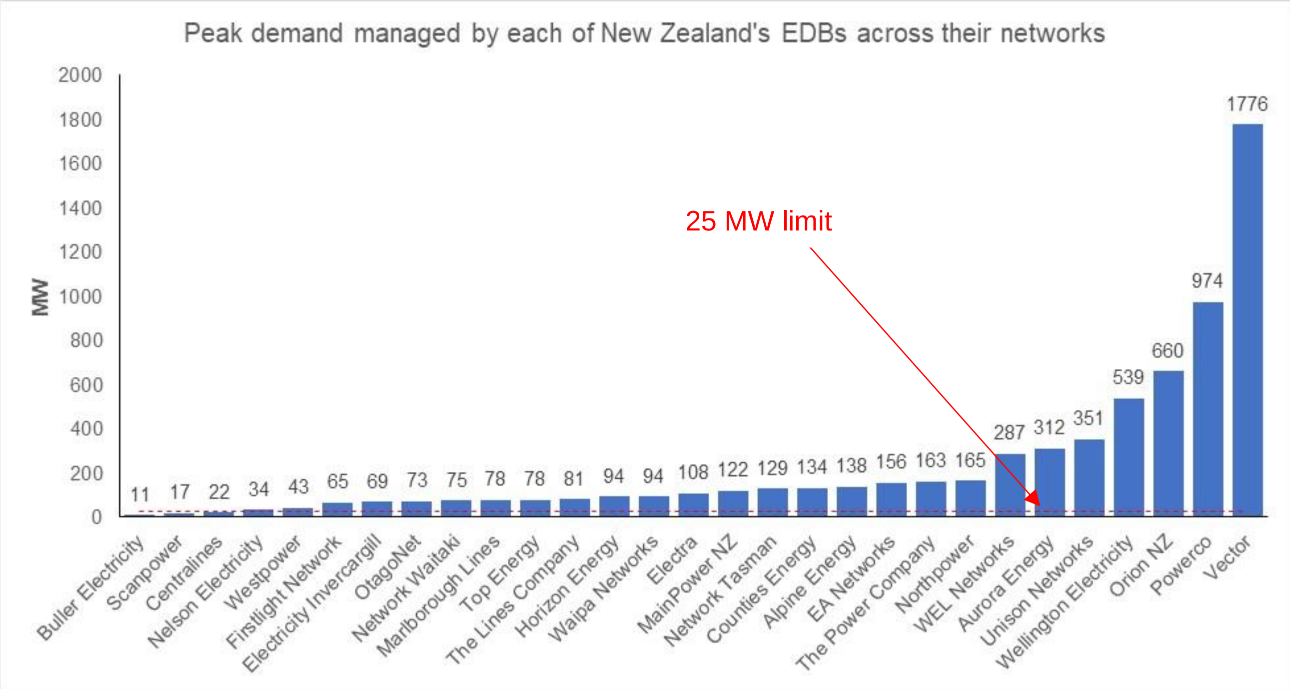
Amending Part 6A to include all generation technology

Vector is a strong advocate for making the Code as technology-agnostic as possible, to ensure innovation can occur with fewer regulatory hurdles.

However, if the definition of "generation" is broadened to include *all* generation technology, expanding further to include batteries, it only follows that the thresholds for permitted ownership of generation should be increased accordingly. If the same MW thresholds are maintained, this means, effectively, that the limits will now be tighter than what was intended by Parliament when they were set. This is more relevant than ever with increasing encouragement by regulators, including the Authority, for distributors to consider alternative options to traditional poles and wires to deliver their network services and increase network resilience.

The current one-size-fits-all threshold for permitted MW of generation set per distributor, is not practical for distributors looking to use generation or storage technology to provide electricity distribution services. Larger distributors will naturally have more potential areas to evaluate the use of generation as an alternative and may also require larger capacity generation to support consumers.

Currently, the same nominal MW limits apply to Vector, with a peak demand of 1776 MW, Buller, with a peak demand of 11 MW, and Powerco with peak demand of 974 MW, who must spread that limit over multiple, geographically-separate networks spanning very different geographies. When peak demands managed by each distribution business (across their various networks)[1] are compared visually, as per the chart below (including the 25 MW limit), the absurdity of the limits per distributor being set on absolute MW terms is clear.



With a 25 MW limit, several of New Zealand's smaller EDBs could meet over 100% of their networks' peak demand with their own batteries, yet still fall under the limit. Entering those markets as a merchant battery provider in those circumstances would be challenging. The same 25 MW limit represents just 1.4% of Vector's peak demand.

We propose that, at a minimum, the limits to generation ownership should scale with the size of networks being managed, rather than by the distribution businesses that own and operate those networks. This could be by ICP count, energy delivered, network peak demand or some combination of those. They should also be set by GXP (or relevant grouping of GXPs), rather than by network owner, to avoid the issue alluded to above that will arise for entities like Powerco owning separate networks that are not geographically adjacent. With some form of scaling, networks can continue to utilise generation as an option to manage network growth while enabling the regulatory oversight appropriate for their size. Both the Authority and the Commerce Commission envision networks utilising the least-cost options to deliver electricity distribution services, which in some cases may be distributed generation or storage.

The Authority should also review the purpose of generation ownership thresholds and whether there are alternatives to the Authority's ability to monitor the impact or risk of distributor-owned

[1] The data plotted in the chart is taken from Information Disclosure data from 2023. The series plotted is 'Demand on system for supply to consumers' connection points', under section 12c(ii) System Demand, for the 2023 forecast year.

generation on the markets of today, or those envisioned in the future.. The existing generation ownership framework creates additional cost and compliance risks when networks approach each of the discrete thresholds, which does limit the potential use of DG by EDBs as a cost-effective network alternative because of the impact on the total cost of pursuing that option. In their review of distribution sector response to Cyclone Gabrielle[2], Energia Limited noted:

> *"Due to our topography, vulnerabilities in the roading networks, and the types of damage that can occur, there will always be some hard-to-restore customers. For these customers and communities, having community hubs with a secure standalone supply of electricity and communication will provide support while restoration or alternatives can be brought online. Community hubs will be an important safety net while hazard reduction and other improvements are made."*

This context should be considered in further development of these thresholds. We note the Authority's intention to publish "Guidelines on threshold for imposing arm's length rules" around June 2024, per the Authority's published work programme for FY24. We ask the Authority to carefully consider the issues we have raised in drafting those guidelines.

Our recommendations above also align with the commitment that the Coalition Agreement between the New Zealand National Party and the New Zealand First includes, to "investigate the threshold at which local lines companies can invest in generation assets"[3]. Undoubtedly this commitment recognises the changing role networks will play in a renewable energy future. It follows that if the threshold to promote investment by networks is increased in the Electricity Industry Act 2010, then the Code must align and the thresholds in the Code be increased accordingly.

Permanent Code amendment to clarify use and availability of discretionary demand control

Firstly, we are disappointed that Code amendments that were first introduced under urgency in April 2023, and not requiring any consultation, are now being proposed to be made permanent via an omnibus Code amendment published just before the December holidays. Intentionally or not, this rushed consultation, and the scattergun approach we note below, risks the proposed Code amendments not being given the scrutiny and consideration warranted.

Secondly, shortly after the Code amendment omnibus publication, the Authority published another related consultation paper, *Potential solutions for peak electricity capacity issues*, in January 2024. This consultation paper refers to the announcement of further analysis **to be** published by the system operator and the Authority, and will be highly relevant to both consultations:

[2] Available online at https://www.ena.org.nz/assets/ENA-EDB-Cyclone-Gabrielle-Review-Report-ISSUED-13-Jul-23-1197.pdf

[3] Page 6 of the Coalition Agreement between the National Party and the New Zealand First Party

> *In January 2024, the system operator intends to publish a detailed analysis of the peak and energy demand challenges that it foresees for winter 2024 and beyond.*[4]

> *The Authority will be releasing an analysis of the notified low residual periods and the industry response later in 2023.*[5]

This rush to publish consultation papers, while related analysis in another paper is not yet available, is inefficient, and results in submissions to these separate but related consultations not being as informed or aligned as they could have been with better coordination between the Authority and the system operator.

Further, it seems that the Authority urgently wishes to have 'provisions/measures' in place for winter 2024, but is trying to rush through the process to make the temporary urgent measures from 2023 into permanent changes to the Code without due and proper consideration. Absent a sunset clause and/or using the EA's rights to temporarily amend Code again, the Authority is introducing long-term provisions that may not be fit for purpose in the future, and is setting a precedent for using temporary urgent Code amendments as an interim step to rush through permanent changes to the Code.

For this consultation, Vector's submissions are focused on the controllable load obligations for networks only. We reserve our observations on broader market issues – including the drivers behind current peak capacity concerns – for our submission on the potential solutions for peak electricity capacity issues.

Obligations are placed only on Distributors

The genesis of the proposed permanent Code amendment for distributors to advise their discretionary demand during shortages comes from MBIE's *Investigation into electricity supply interruptions of 9 August 2021*[6]:

> *In short, the SO must have full visibility of discretionary load available through ripple control, enabling better and more accurate use of this valuable resource. This should be done as a matter of priority – before the winter of 2022.*
>
> *…*
>
> *We recommend that the Code must be amended so that the SO has real time, and acceptably accurate, awareness of discretionary load available from each EDB by winter 2022.*

[4] Para 2.26 of Consultation paper: Potential solutions for peak electricity capacity issues
[5] Para 2 of Appendix A of Consultation paper: Potential solutions for peak electricity capacity issues
[6] Para 5.2 of Investigation into electricity supply interruptions of 9 August

The initial recommendation for distributors to advise quantities of discretionary load available through ripple control to the system operator has now morphed into a proposed permanent obligation for distributors to advise and use a broad range of resources, without considering other market participants who may have the same or comparable resources, including controllable load, batteries, embedded generation, etc. Only distributors are singled out for these obligations.

The Authority's intention to expand the obligation from using ripple control to also include connected batteries and various forms of generation may have gone under the radar somewhat, but is clear from paragraph 3.9 (our emphasis added):

> *We also propose adopting the term "quantity of resources" over "quantity of demand". This is intended to reflect the characteristics of different distributors which may have **a broader range of resources available than just demand control**. This would enable a difference bid to reflect the total net reduction in load at a grid exit point that is available to be utilised (**whether by controlling demand or increased network support generation**). Note that market offered embedded generation is still proposed to be excluded from controllable load difference bids.*

The range of parties who have such resources at their disposal is clearly much wider than those who have some manageable load. Vector therefore strongly opposes the notion that obligations to dispatch controllable resources should apply only to distributors, and proposes that any obligations should apply to **all** market participants. Many other parties are currently developing and acquiring the ability to manage consumers' loads and/or other distributed resources, with a range of different motivations, and there is no obvious reason why the proposed Code amendment applies only to distributors.

Consideration of costs

In the consultation paper on potential solutions for peak electricity capacity issues, the Authority acknowledges that participants already offer or withhold capacity on commercial grounds and that this is reasonable behaviour for a market participant:

> *Growing renewable generation, both intermittent and baseload such as geothermal generation, is pushing old slow-start baseload thermal plant to be used more in a peaking capacity. As these technologies have lower operating costs than thermal plant, they tend to reduce the average wholesale market price. This erodes the commercial incentive to warm up slow-start thermal plant just in case they are needed to cover brief periods a few times a year. This has been exacerbated by the increasing carbon price and recent uncertainty in fuel availability increasing thermal plant running costs.*[7]

[7] Para 2.29 of Consultation paper: Potential solutions for peak electricity capacity issues

Of note, the Authority does not go on to propose that generators be required to offer and run their plant at a commercial loss at times of potential capacity shortages. Therefore, we would expect the Authority to also take into consideration the costs that other parties may face for operating controllable load at times of capacity shortages as well.

Like ripple control systems, assets such as batteries and distributed generation require significant up-front capital investment and ongoing maintenance costs. The energy to fill batteries comes at a cost, and diesel back-up generation has a material operating cost and carbon emissions impact. Therefore, these cannot be considered costless options for the SO and other market participants; such an assumption will not support the development of flexibility markets in future.

The type of available resources and the way distributors operate them mean that the existing methods of receiving compensation from the wholesale market (such as offering via Dispatch Notification) are not easily accessible. The costs of putting new processes in place to enable compensation from the wholesale market may be difficult to justify for the rare occasions (perhaps once in a couple of years) that these assets are required to operate at the instruction of the system operator.

Multiple parties will be managing load in future, and distributors will have new tools

Further, over time, the ability for distributors to calculate how much of a particular resource is "available" will become more complicated. Several retailers are now acquiring the ability to manage hot-water load via smart meters, and if dual control of hot water cylinders becomes feasible, this will require coordination between those retailers and their host distributors to adequately forecast the available load.

For example, one of the tools that distributors are exploring in Australia and New Zealand to manage demand from distributed generation and manageable loads is a dynamic operating envelope. These would not involve directly controlling devices, but rather setting boundaries for allowable generation or consumption for devices. In theory, at times of emergencies, demand could be managed by setting the allowable limit for consumption to 0kW, thereby minimising the peak demand impacts. However, this would not necessarily be reflected in SO forecasts, as it depends entirely on what the parties managing those devices may have intended otherwise, and most likely this avoided demand could not be bid in as available controllable load, as there is no ability to measure performance.

Further, both distributors and retailers managing the same hot-water loads via different technologies also raises uncertainty about the quantities distributors will have available to control at the instruction of the SO. It is entirely possible that retailers will choose to drop all their hot-water load in the lead-up to a grid emergency, due to high spot prices, leaving nothing for the distributor to control if and when the emergency is actually declared.

Relatedly, we note that the proposed amendment is silent on the question of how post-emergency load restoration on distribution networks is orchestrated. This has not been an issue in the past, as distributors were the sole party with the ability to manage material quantities of load. Restoration of that load has always been very carefully orchestrated so as not to overload the network – it can take several hours for hot water restoration alone. We call this "the forgotten side of load management"[8].

We can foresee a future scenario with multiple aggregators turning load off in the lead-up to, and during, a grid emergency, and then wanting to restore that load as soon as spot prices fall post-emergency (potentially to meet service-level agreements with their customers). This is a potential disaster for distribution networks – as is well known, spot prices do not reflect at all the physical and power quality constraints on local networks, which could be breached if a large quantity of load is restored in a synchronised fashion.

We have advocated over the past year for the distributor to have the power and precedence to orchestrate the restoration of load by all parties on the local network, post-emergency, rather than the SO, as the SO has no visibility whatsoever of what rate of load restoration can be accommodated in what areas. The Code, as it relates to grid emergencies, is silent on this matter, and non-retailer aggregators are not even covered under the Code.

Sunset provision and appropriation

The Authority acknowledges in the second consultation paper that they wish to limit the impact that any measures implemented now may have on the incentive to innovate and invest in the future:

> *The Electricity Authority Te Mana Hiko is conscious that initiatives implemented to manage near-term issues, say the next one to two years, should not disincentivise innovation and investment for the medium and long term.*[9]

Given how rapidly this space is evolving, we think that there should be a sunset clause for the Code obligation on distributors. Alternatively, at a minimum, the Authority should commit to reviewing the efficacy of these rules prior to winter 2026.

As another option for winter 2024, the Authority could again use the temporary Code amendment process, with some changes based on learnings, and then revisit the requirements for Winter 2025 with the benefit of additional data and time for more responsive supply side resources to become available. In an effort to ensure measures are in place for winter 2024, we feel the Authority is rushing through permanent Code amendments, when the better approach would be to consult on these measures alongside related workstreams over the course of the year for winter 2025.

---

[8] See our post on this issue here: https://www.esig.energy/the-forgotten-side-of-load-management/

[9] Executive summary of Consultation paper: Potential solutions for peak electricity capacity issues

Transparency

Finally, we suggest that rather than relying on market participants making UTS claims to trigger an investigation, a Code amendment should include an obligation for the Authority to investigate each and every occasion during which the system operator instructs participants to use controllable load in an emergency. Given the expected rarity of these events, this obligation would not be onerous but would provide additional confidence to all market participants that good electricity industry practice is expected in emergencies, and controllable load (and other resources) subject to difference bids will genuinely be used as a last-resort option. This would be analogous to the investigations undertaken in Australia during high-priced periods.

Responses to specific questions posed in the consultation paper

The remainder of our submission responds to the specific consultation questions set out in Appendix D of the paper.

Include all generation technology in Part 6A

Q1.1. Do you support the Authority's proposal to include all generation technology under Part 6A?

Vector supports the proposal to include all generation technology, but only on the condition the thresholds for EDB ownership of generation are reviewed and increased accordingly, as per our comments above. Otherwise the limits are effectively being tightened over what was intended by Parliament when they were introduced (particularly due to the inclusion of batteries).

Q1.2. Do you support the Authority's proposal to create a new definition for "connected generator"?

We suggest the new definition needs further clarification. For example, does it include generation without synchronising capability[10], which is only 'connected' and operated once the network is de-energised and safely islanded from the national and local networks? We have several facilities with generation that is not able to synchronise with the grid. We can isolate the network serving a community and use non-synchronous generation to provide a limited service as we undertake repairs to the network serving that community.

Q1.3. 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

[10] A synchronous generator runs exactly at a synchronous speed to match the grid frequency and can be safely operated while it's connection to the grid is energised.

We agree the proposed amendment is preferable to the other options for now, however, we do believe there would be merit in periodically reviewing all of Part 6 to ensure it keeps up with the rapid change in technology and how it is being used by distributors.

Q1.4. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

We disagree with the Authority's consideration that there are no costs associated with the proposed amendments. It will increase distributors' compliance costs unless the thresholds are adjusted appropriately (as per our comments above).

Q1.5 Do you have any comments on the drafting of the proposed amendment?

Other than increasing the thresholds for the reasons noted above, we have no other comments on clause 6A.1

See also our comments above on amendments to the definition of "connected generation".

Clarify use and availability of discretionary demand control

Q2.1. Do you support the Authority's proposal to permanently implement the intent of the urgent Code amendment, Electricity Industry Participation Code Amendment (Discretionary Demand Control) 2023?

We **strongly oppose** the Authority's proposal as it stands; see our comments above.

Q2.2. Do you support adopting the term controllable load?

We agree the term controllable load is clearer and better aligned with the intent of the Code.

However, we, and others in the industry, prefer to use the term "manageable" rather than "controllable". It demonstrates that the resources are being operated and managed at the request / behest of the consumer who owns them.

Q2.3. Do you support the use of the term 'resources' over 'quantity of demand'?

We think this needs to be given more explicit attention and communication by the Authority. While we understand the desire to broaden the definition outside of just manageable load, we believe that the same obligations should be placed on other, non-distributor, electricity participants who also own or have the rights to manage the same types of resources.

There also needs to be more clarity about which resources should be considered 'available' and which resources are not. For example, some 'resources' may appear to be available to distributors, but distributors may not have the direct visibility of future quantities and thus the capability to accurately inform the SO of the quantity of manageable load available for an emergency. This is especially the case when third parties are involved, such as retailers managing hot water load via smart meters.

Q2.4. Do you support the proposal to introduce two price-bands?

The proposal is unclear about how distributors are meant to differentiate between 'requested' and 'instructed' controllable load. If the system operator issues a request under a formal notice, including a Warning Notice, then the distributor must use reasonable endeavours to respond to the request. So, in our view it makes little difference for the distributor whether it is requested or instructed to control load in a difference bid, in terms of levels of obligation to comply. Is the SO expecting distributors to have differing levels of confidence in the quantities provided in each tranche?

Q2.5. Do you support pricing requested controllable load at $0.01/MWh?

We **do not support** a price band of $0.01/MWh. If the system operator makes a market intervention as a result of scarcity-like-conditions, and noting our comments above about a distributor's stringent obligation to respond to a request under a (formal) Warning Notice, then it should be priced accordingly at $9000/MWh.

Q2.6. 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 agree that the proposed amendment is preferable to the two options identified in the paper, however, we **do not agree** that the proposed amendment should be made permanent at this stage.

Instead, it should either be a further temporary change or a permanent change with a sunset provision of three years, which would allow the Authority time to consider a wider range of options.

Further, we note that the proposed amendment is silent on the question of how post-emergency load restoration on distribution networks is orchestrated. This has not been an issue in the past, as distributors were the sole party with the ability to manage material quantities of load. Restoration of that load has always been very carefully orchestrated so as not to overload the network – it can take several hours for hot water restoration alone. We call this "the forgotten side of load management".

We can foresee a future scenario with multiple aggregators turning load off in the lead-up to, and during, a grid emergency, and then wanting to restore that load as soon as spot prices fall post-emergency (potentially to meet service-level agreements with their customers). This is a potential disaster for distribution networks – as is well known, spot prices do not reflect at all the physical and power quality constraints on local networks, which could be breached if a large quantity of load is restored in a synchronised fashion. We have advocated over the past year for the distributor to have the power and precedence to orchestrate the restoration of load by all parties on the local network, post-emergency, rather than the SO, as the SO has no visibility whatsoever of what rate of load restoration can be accommodated in what areas. The Code, as it relates to grid emergencies, is silent on this matter.

Q2.7. Do you agree with the analysis presented in this Regulatory Statement? If not, why not?

We **do not agree** with the Regulatory Statement on a number of fronts, including:

- The $0.01/MWh does not send the appropriate price signal to the market when the system operator intervenes to avoid, or during, scarcity-like-conditions
- The proposal does not include any compensation for costs incurred by distributors using controllable load or other resources.

Q2.8. Do you have any comments on the drafting of the proposed amendment?

In addition to our various comments above, we suggest the following changes to the definition of "controllable load", or "manageable load" as suggested above:

- "(i) resources a connected asset owner intends to use for ~~its own network demand management purposes~~ the purpose of delivering electricity distribution services" – this broader definition would include resources required for purposes other than peak management, for example managing voltage
- "(ii) any resources offered ~~into the instantaneous reserves market~~ as an ancillary service to the system operator" – this broader definition would include other ancillary services than reserve, for example frequency keeping.

Updating and clarifying the scope and effect of Part 6A obligations

Q3.4. Do you have any comments on the drafting of the proposed amendment?

It is unclear what form of 'distribution agreement' the Authority considers appropriate to comply with the proposed amendments to clauses 6A.1 to 6A.4. Both the Default Distributor Agreement ("DDA") and the Regulated Terms for distributed generation at schedule 6.2 in Part 6 of the Code ("Regulated Terms") seem to be 'appropriate' distribution agreements. We note at least one EDB is using the Regulated Terms to comply with the previous requirements (now repealed) in the Act. On the other hand, the now repealed clause 77 of the Electricity Industry Act 2010 refers to a 'use of systems agreement.'

There may also be situations where a 'specified person' (such as a director) is involved in both a distributor and retailer, where the businesses are already corporately separate and already have a DDA in place between the two parties. Does the Authority consider the DDA to be the appropriate distribution agreement to comply with the requirements of clause 6A.4?

The Regulated Terms are the terms upon which customers usually connect distributed generation to their host network. This is presently Vector's practice. However, given the proposed amendment to the definition of 'connected generation' and the unchanged generation thresholds, more EDBs may now need to meet the requirements of clause 6A.4. How do they then reconcile the situation described above (with respect to a specified person) and BAU practice with offer of Regulated Terms for connected or distributed generation? Clause 6A.4 requires distribution agreements to be non-discriminatory and to *"not omit elements that the business usually includes in distribution agreements"*? The Authority needs to clarify this and ensure amendments are consistent with practice, before proceeding further. We also note the prescribed form of annual statement at clause 6A.4A of Appendix C, which may have provided useful guidance, was not included in the Consultation Paper.

We also question the need to publish and provide to the Authority the form of any distribution agreement entered into under Part 6A. Both the DDA and Regulated Terms are in or arise out of the Code. The DDA is already required to be provided to the Authority and be published on a distributor's website. There is therefore no merit and only administrative burden for both the Authority and the distributor in making this an additional requirement. We suggest DDAs and Regulated Terms be exempted from the need for publication and provision to the Authority.

Likewise, the need to provide annual declarations/statements under clause 6A.4 and 6A.5 add little value for the same reasons above. Both the DDA and Regulated Terms are Code-related agreements, are widely used and widely complied with by the industry. There is very little evidence or risk of non-compliance and as an alternative compliance could be added to the participant audit requirements instead. If the requirement to provide an annual declaration is to be retained, then we think it should apply **only** if another form of agreement (e.g., a bespoke agreement) is entered into between the distributed and a connected generator/retailer. It should be an exempt requirement if the DDA or Regulated Terms are used. Instead, the obligation to demonstrate compliance could be added to the annual or cyclical distributor audit.

Feedback on the omnibus format

Q4.1 Do you consider the omnibus format should be continued as a way of consulting on several small but independent separate Code amendments?

We consider the omnibus format could be useful for certain Code amendments, however, we believe that both the Code amendments in this omnibus should have been consulted on separately and more comprehensively. These are not technical and non-controversial. Note also our comments about timing and coordination above.

Q4.2. Do you have any comments on the omnibus format or suggestions to improve the omnibus format?

It is unclear why the amendment to clarify use and availability of discretionary demand control is sandwiched between two sections on Part 6A and makes for confusing reading. Also, the misalignment between the questions posed throughout the paper, and those summarised in its Appendix D, confirms our comments above about the proposal being rushed.

Yours sincerely

J. Tipping

Dr James Tipping
GM Market Strategy / Regulation