

To: ELECTRICITY AUTHORITY

From: Electricity Engineers' Association of NZ

Date: 12 October 2026

Subject: EEA submission – Plug-in generation and distributed generation-related Code changes

OVERVIEW

The Electricity Engineers' Association of New Zealand (EEA) welcomes the opportunity to provide feedback on the Authority's proposals concerning plug-in generation and distributed generation-related Code changes.

The EEA represents and supports members across Aotearoa New Zealand's electricity sector. Our purpose is to guide and equip the sector so that it can electrify Aotearoa. Our membership includes over 70 company members and over 600 individual members, covering the electricity supply industry and its workforce.

Our mandate focuses on technical best practice, including workforce and public safety, workforce capability, and connecting the sector to learn and collaborate. We promote standardisation and consistency where these deliver practical benefits for the industry and electricity consumers.

Overall Position

The EEA supports enabling consumers to adopt distributed energy resources through clear, proportionate and efficient connection arrangements. These arrangements must maintain electrical safety, network reliability and power quality, while supporting affordable outcomes for consumers over the longer term.

Consistent national requirements can reduce complexity and unnecessary costs. However, they must also accommodate legitimate differences in network conditions and preserve distributors' ability to plan for future uptake.

While this consultation focuses on technical issues, consideration of potential consumer safety issues should not be overlooked, to ensure that New Zealand consumers are guided to locate, maintain and operate plug-in solar safely.

Plug-in generation – Appendix C

The EEA supports a proportionate, light-touch approach to small-scale plug-in generation, underpinned by appropriate equipment performance and installation standards. These standards should address electrical safety, cumulative capacity where multiple devices are connected, and the safe installation of solar panels.

Our submission supports a simplified process for compliant systems below an appropriate capacity threshold where consumers do not seek payment for exports. Any notification or registration

requirement should be supported by evidence that its benefits outweigh its costs. Where consumers seek payment for exports, we support an appropriate Part 6 application and approval process.

Clear consumer information is also essential. Consumers should understand installation requirements, the benefits of self-consumption and storage, and the risks of relying on current electricity buyback rates when making investment decisions.

Distributed generation-related Code changes – Appendix D

The EEA supports greater consistency between Part 1 and Part 1A connection processes, including the application of the default 10 kW export limit, access to both application pathways, and clearer processing timeframes. We also support protecting consumer choice by avoiding mandatory requirements for communicating smart inverters or flexible export arrangements at this stage.

However, we seek clarification of the proposed 10% allowance for network assessments. Increasing the capacity of existing generation is not equivalent to increasing the number of premises with generation, and these approaches can produce materially different network outcomes.

Our submission therefore supports allowing distributors to assess export limits against reasonable future uptake scenarios, with an interim cap of 35% penetration as proposed in Appendix D. This would support effective network planning, fair access for future applicants and more efficient use of existing capacity.

Supporting implementation

The EEA's connection guidelines and joint work with the Authority on the ELAM/BELAM National Framework Guideline provide practical support for consistent implementation. We welcome continued collaboration with the Authority and the wider sector to ensure regulatory changes are technically sound, workable and supported by clear guidance.

Our detailed responses are attached as **Appendix C – Plug-in generation** and **Appendix D – Distributed generation-related Code changes**.

Contact

For further information or to discuss this submission, please contact:

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Submission form (Plug-in generation)

Please email your submission to: connection.feedback@ea.govt.nz by 5pm, Tuesday 6 October 2026

Name	Dr Kannan Munisamy Engineering and Technical Lead
Organisation	EEA

Questions on issues regarding plug-in generation

Questions	Comments
Q1. Do you have any views on our characterisation of plug-in generation?	Referring to plug-in-generation is sensible, since it allows for inclusion of other forms of generation. Plug-in-generation comprising solely of batteries should also be considered.
Q2. What network performance requirements should apply to plug-in inverters in New Zealand, and why?	While this question is about performance requirements (standards), we believe that installation requirements (standards) should also be considered. Performance requirements The Electricity Authority notes in its consultation paper (4.36) that, like Germany, New Zealand may ultimately see many plug-in generation systems installed. In this respect, the same performance requirements as fixed inverters are preferable. However, New Zealand is subject to appliance availability and performance set to meet international markets. It would be unreasonable and/or over burdensome to restrict the availability of plug-in generation to New Zealand consumers by insisting on a standard unique to New Zealand and which internationally available plug-in generation cannot meet. Hence further work is required to understand what performance levels the available plug-in generation equipment can meet. Thereafter: (a) tailor New Zealand standards to this, and (b) participate in efforts to set new international standards for this equipment taking New Zealand performance requirements into consideration. To reduce installation overheads and therefore barriers to uptake, it may be appropriate to classify plug-in-generation by capacity, as alluded to in the consultation paper 4.35. This capacity might be determined by ratings of what is commercially available. For example, below 800 Watts may not require additional performance requirements, whereas above this capacity may require the same performance requirements as fixed inverters (as well as additional safety requirements). Installation requirements Where more than one system below this threshold is connected at a single ICP, these standards would be required, or such installation prohibited. Warnings around connecting more than one system should be provided by the retailer of the plug-in system, including warnings around connecting them on the same circuit. This is to deal with the risk of gradually increasing the

	total capacity by periodically purchasing and connecting smaller systems. It is expected that the installation and performance standard would deal with the above including the requirement for warnings. Noting that the consultation paper refers to ongoing work on an "...alternative installation standard for plug-in generation." (4.28, 4.29, 4.30), that work should <i>also</i> consider safe installation of PV panels such that they do not present a safety risk during high winds and / or from installation at a height, particularly above public spaces such as roads and walkways.
Q3. What do you think of the Authority excluding plug-in generation standards from the Code?	We support exclusion of plug-in generation standards from the Code, provided there is a comprehensive plug-in generation standard relevant to New Zealand that deals with both installation and performance. It may be appropriate for the Code to refer to there being a plug-in generation standard, and where (e.g. ESRs) that standard is required. While neither directly relevant to the current consultation nor the Electricity Authority, we note that citing the plug-in standard in the ESRs may lead to the same issue of outdated standards as seen before for fixed distributed generation systems, and other standards.
Q4. Do you agree that in the absence of a professional intermediary, it will be challenging to obtain a Part 6-type application from a plug-in generation consumer? Why, why not?	Yes, it will be challenging to obtain a Part 6-type application from a plug-in generation consumer. The Code, and Part 6 application, is a specialist document and process. It is unreasonable to expect consumers to engage with this when installing what is essentially an appliance, or to employ a specialist to complete the application on their behalf. However, in exchange for a simpler connection process, strict adherence with performance and installation standards (referred to above) should be required. Plug-in generation retailers should be responsible for selling equipment that adheres to performance standards, and providing consumers with appropriate information on installation standards. Appropriate publicity and warnings must be provided about purchasing plug-in generation equipment online from international sellers, with the use of such equipment in New Zealand prohibited.
Q5. For a consumer to connect plug-in generation to their premises, should some form of Part 6-type application process be required? Why, why not?	A Part-6 type application process should not be required provided: (a) payment for plug-in generation export is not intended to be claimed, (b) plug-in generation meets the performance standards referred to in Q4 and is installed in accordance with the installation standards referred to in Q4, and (c) information about its sale is notified and collected (see Q6 below), subject to the benefits of this outweighing the costs. The reason why the Part-6 type application is not required is compliance with standards and collection of sales information, as well as the discussion in response to Q6.

	Furthermore, a nationally standard framework for sale and use of plug-in generation would ensure it is a more efficient and cost-effective solution for consumers who may not have the resources or ability to access fixed PV generation systems.
Q6. If a form of Part 6-type application process should be implemented for plug-in generation, do you see that is a notification/registration, or an application that requires distributor approval? Why?	As in Q4 and Q5 a Part 6-type application should not be required, but a notification process provides information about the installation of plug-in generation. Implementation of such a process should follow consideration of a cost-benefit study and only be required if the benefits (such as increased information that enables distributors to more efficiently operate and plan their networks) are shown to outweigh the costs. There should be no need for distributor approval provided the plug-in generation is below a threshold capacity and complies with the relevant performance and installation standards. Further reasons for our response to this question are given below. It is not necessary to notify a distributor, or any other participant, including via the registry, of the installation at an ICP of any other appliance that may significantly alter demand. For example: • the replacement of resistive space and / or water heating with heat pump(s), • replacement of incandescent lighting with LED lighting, or • installation of a high capacity (7.4 kW) EV charger. To do so would be an unreasonable imposition on the consumer. As smart metering and data analytics improves, electricity industry participants should use these measures to understand consumption of consumers rather than rigorous information collection that imposes on consumers' time and privacy. We presume notification of installation of plug-in generation is being contemplated due the possibility that it may result in export. We believe this is largely dealt with in our response to Q15 below.
Q7. What information should be required if a registration or application for a plug-in generation unit is to be implemented?	The following information should be collected when plug-in generation is registered, if as in Q6 the benefits are shown to outweigh the cost: • Address of installation, • Name of owner of the plug-in generation, • System capacity (both inverter AC capacity, clearly labelled on the product as noted in 4.62, and DC power generation capacity if any), • Storage capacity (kWh) if any, also clearly labelled on the product, • Performance standard that the plug-in generation adheres to, • Installation standard required, • Acknowledgement of the need to install the plug-in generation such that it complies with the installation standard. This might be efficiently managed at the point-of-sale, with the ability for the owner of the plug-in generation to update it if they move address for example. A system that prompts for this update would be preferable.

Q8. Would participants benefit from a registry that captures information about plug-in generation? Why, why not?	Participants may benefit from a registry that captures information about plug-in generation for the reasons given in the consultation paper. In addition, electricity distributors may benefit by better management and planning of their networks. However, whether that benefit outweighs the cost of implementing and managing collection of plug-in generation information is questionable. It is also questionable how relevant the registry will remain, given that plug-in generation may move address without notification. Additionally, as noted in the response to Q6, substantial changes in demand at ICPs from new appliances can already occur without notification. As alluded to in our response to Q6, the use of smart metering and data analytics might be a more effective means of understand demand at each ICP. Whether the benefit outweighs the cost should be tested as part of the cost-benefit study suggested in Q6.
Q9. Should the existing registry be used? Why, why not?	If information about plug-in generation is to be collected, the registry would be a suitable means to retain such information, rather than creating a new system. However, given that our responses do not support a Part 6 process to collect such information, it may be complex to interface another means of collection (e.g. point of sale) to the registry.
Q10. Should entering information about plug-in generation be a requirement only after export has been identified at an ICP? Why, why not?	Given the discussion in our response to Q6 and later questions, this may be a suitable trigger to collect information.
Q11. Would the type of information able to be collected at point of sale be sufficient to meet industry needs? Why, why not?	Yes, the type of information able to be collected at the point of sale is sufficient (see Q7 response) provided there is the mechanism to update the address of installation of the plug-in generation.
Q12. Should the MEPs reverse power indicator be leveraged in identifying potential plug-in generation export? Why, why not?	We cannot comment on that – it is a matter that warrants further investigation including the cost of providing such a service.
Q13. Do you agree there is merit in considering whether retailers should be the primary customer interface for plug-in generation registration/notification? Why, why not?	Yes there is merit in considering retailers as the primary customer interface for plug-in generation registration/notification. This is for the reasons given in the consultation paper 4.67 and 4.68. Note however that this does not necessarily mean that the plug-in generation will also change address.
Q14. Do you have any other suggestions on how consumers could be informed of Code requirements for plug-in generation?	See our response to Q4, last paragraph, although that deals with a standards compliance requirement rather than a Code requirement.
Q15. Should an ability for plug-in generation consumers to receive payment for export be predicated by some form of Part 6 application and approval process? Why, why not?	Yes, the ability for plug-in generation consumers to receive payment for export should be predicated by a form of Part 6 application and approval process. This differs to our previous responses because the consumer has sought to be paid for export. This carries additional costs, benefits for the consumer, but also risks, which are discussed

	below. Such an application might also apply to plug-in generation above the threshold mentioned in our comments at Q2. While in general our responses have sought a 'light-touch' treatment of plug-in generation, exporting to the network and expectation of payment represent a different use of the network. In addition, it may be assumed that once energy is being sold, larger volumes may be exported, and therefore the capacity of exports increased. Balancing this is the situation where exports may reduce in value over time as more solar connects to the network and buyback prices drop – something already seen in Australia. There is a risk of raising consumer expectations that summer daytime and possibly even winter daytime buyback prices will remain high. This may encourage consumers to invest more in an export meter and the cost of the Part 6 application, rather than arrange demand and/or energy storage to increase self-consumption of the plug-in generation. We believe consumers would benefit from more information about plug-in generation, specifically solar with or without storage, to assist them make more informed choices. The most obvious starting point for this is information provided by the retailer of the plug-in system before and after purchase. Another possibility is extension of the EECA solar payback calculator to plug-in solar, and / or plug-in energy storage. Both should combine with information on the risks of purchasing a system on the assumption that current pricing (especially buyback) will persist. Some simple modelling, specifically of plug-in solar, shows the following (the appendix gives an expanded version of these points): System cost is critical: Halving the cost of plug-in solar can reduce the payback period by more than half. Summer self-consumption is particularly important: Higher summer daytime self-consumption substantially improves payback, given the greater availability of solar generation. Winter self-consumption also matters, but less: Its impact on payback is smaller because solar generation is lower in winter. Buyback credits can materially improve payback: At current buyback rates, payback is around 8–11 years in the modelled scenarios. Future buyback rates are a key risk: If summer buyback rates fall to zero, much of the benefit of exporting electricity disappears. Increasing self-consumption using energy storage could mitigate the risk identified in e: Batteries or hot-water heating could increase self-consumption and potentially reduce payback to around 6–7 years, depending on cost. The value of plug-in generation combined with energy storage may be improved even further if the plug-in generation is able to generate during peak periods and thereby offset peak demand at the ICP and on the network. This might be arranged by having it respond to retail prices that are higher during peak periods. Such operation may completely avoid the need to export, and thereby avoid the costs and risks
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	identified earlier. This would benefit the plug-in generation owner as well as the network and ideally all consumers by reducing peak demand and therefore the need for network upgrades. In this case, the form of Part 6 application and approval, should be the means of collection of plug-in generation information and entry into the registry. By contrast, where a consumer purchases plug-in generation but does not apply for export, no information ought to be collected or retained in the registry (unless the benefit of collection of such information outweighs the cost of collection – per our earlier responses).
Q16. What measures could be implemented to inform consumers of electricity export at their ICP that is potentially associated with plug-in generation, and what information should this include?	We have interpreted this question to mean electricity export actually occurring at an ICP because of a plug-in generation. In this case the electricity retailer or distributor might inform the occupant at the ICP if export is over a 'to be determined' threshold of capacity and/or energy.
Q17. Should consumers be proactively informed of the potential for plug-in generation to export to a network. If so, which party is best placed to undertake this education role?	Consumers should be informed of the potential for plug-in generation to export to a network. Our response to Q15 deals with informing purchasers more generally about plug-in generation, how to optimise it and reduce its payback. This includes export, the risks associated with export, the importance of self-consumption, and ideally how to use the plug-in generation to maximise self-consumption. It is essential that consumers are also proactively informed about safety considerations concerning the location, installation and maintenance of plug-in solar. It would be preferable for all consumer messaging to come from the same source.
Q18. What issues do you see with more UFE in the reconciliation system as a result of more export from plug-in generation?	We note that improvements in energy efficiency have reduced energy consumption at ICPs. Two examples are transition from resistive heating to heat pump heating and transition from incandescent lighting to LED lighting (which may or may not include an intermediate step of CFLs). We estimate that, across the same number of ICPs, the reduction in energy consumed by each of these energy efficient transitions is estimated to amount to roughly the same amount of energy produced by 800 Watt plug-in solar generation. There has been no effort to account for this energy reduction in the reconciliation process. However, we acknowledge two important differences. First, that plug-in generation may lead to export, whereas the energy efficiency measures mentioned above do not. If it were not for export, we would suggest treating the plug-in generation the same as energy efficiency. Second, the two energy efficiency measures mentioned previously (namely heating and lighting) are generally coincident with peak demand, and therefore have the benefit of reducing peak demand and therefore a driver of network investment. By contrast, plug-in PV generation is likely to not reduce peak demand, as it generates during the day.

	We acknowledge the issues outlined in the issues and consultation paper when plug-in generation uptake grows substantially.
Q19. Do you agree with our view that plug-in generation export with no measurement enabled can be treated as UFE in reconciliation processes, with no need for formal gifting documentation? Would your view change as plug-in generation increases?	We agree with the view that as stated. As stated in 4.91 of the consultation paper initial uptake is likely to be low. Furthermore, increasing self-consumption using energy storage should be a less risky option for the consumer than export (see our response to Q15). In this case export would be lower, and the issue of UFE may reduce. Rather than focus on the UFE energy issue and export, it would be preferable to encourage energy storage paired with plug-in generation to reduce exports and peak demand. This view re encouraging self-consumption is aligned with preparing for increasing levels of plug-in generation.
Q20. If gifting documentation were to be required by a plug-in generation consumer, how could this be facilitated?	It would be preferable to avoid the need for this, and instead concentrate on maximising self-consumption, especially over peak periods, as above.
Q21. Are there other genuine issues identified by the reverse power indicator?	No response.
Q22. Should the requirement on the MEP to notify the retailer via a reverse power indicator be reconsidered, if more plug-in generation is used? Why, why not?	Yes, provided the process in our response to Q23 is in place.
Q23. Is there a way for a MEP to filter out plug-in generation related reverse power indicators?	Our earlier responses suggested considering the costs and benefits of holding a registry of plug-in generation when the owner has not applied for export. This may be one of the benefits of holding a registry of plug-in generation. If timing of reverse power indication coincides with export from PV, and the ICP has plug-in solar recorded, it may be ignored.
Q24. Should Part 10 include an exclusion for requiring import/export metering for plug-in generation? Why, why not?	We agree with this rather than requiring the consumer to complete gifting documentation based on reducing complexity for the consumer.
Q25. Should Part 6 clarify requirements for a plug-in generation system being connected alongside approved permanently-fixed DG?	Yes it should, as installation of fixed DG indicates a level of commitment beyond a simple 800 W or lower plug-in generation system and warrants the additional complexity. However, the installer of the fixed DG system will most likely have engaged with the distributor and necessary application to satisfy Part 6, not the consumer. Hence the consumer may be unaware of their obligations. In this respect the information provided with the plug-in generation at the point of sale (referred to in previous responses) should make it clear that installation alongside existing fixed DG requires an application to the electricity distributor to update inverter capacity.
Q26. Should the Code clarify limits on the amount of plug-in generation capacity that can be connected at an ICP (noting any standards developed may define limits)?	If standards define limits this is unnecessary (aside from installation alongside fixed DG as above). However, the limits must be clearly stated at the point of sale. Our responses throughout have been on the basis of single plug-in generation systems limited in capacity to 800 Watts. Where

	either this number and / or this capacity is exceeded, it warrants consideration of an approval process under Part 6.
Q27. What sources of information could the Authority use to monitor uptake of plug-in generation and/or any issues that may arise?	
Q28. Do you agree with our overall characterisation of the challenges of plug-in generation? Why, why not?	Yes, the paper is thorough in its identification of the challenges and related issues of plug-in generation.
Q29. Which of the challenges outlined in this paper present the most pressing issue for the Authority to address?	The most pressing issue for the Electricity Authority to address related to ensuring a 'light-touch' process for consumers to install plug-in generation while ensuring compliance with performance and installation standards. This includes not installing systems over a given capacity without first applying under Part 6, and / or not installing multiple systems without first applying under Part 6. The electrical safety issues raised elsewhere in relation to plug-in generation are of the utmost concern. This is why only a single system limited to 800 Watts (or some other similar limit consistent with available equipment) is appropriate. Following these is the need to deal with exports if a consumer wishes to do this.

Appendix to Q15

This appendix expands on the points made in response to Q15 by use of a simple model. The model considered an 800 Watt plug-in PV system costing \$1,800, average summer daytime self-consumption of 200 Watts, average winter daytime self-consumption of 500 Watts, a retail price of 36 c/kWh and a default buyback price of 14 c/kWh. The combined cost of an export meter and Part 6 application is assumed to be \$250. To calculate payback times a real discount rate of 5.37% is used (based on a nominal cost of capital of 8% per annum and inflation rate of 2.5%). An average annual capacity factor of 0.15 is assumed, which is halved for winter and doubled for summer.

The expanded points, relating to each in the response to Q15, follow.

- a. **System cost has a significant effect on payback.** The model indicates that reducing the cost of a plug-in solar system from approximately \$2,200 to \$1,200 reduces the payback period from about 28 years to about 10 years. This example excludes any income from exporting electricity.
- b. **Summer daytime self-consumption is a major driver of payback.** At current retail electricity prices, and without buyback credits, increasing average summer daytime self-consumption from 0.1 kW to 0.4 kW reduces the payback period from more than 30 years to around 10 years, assuming average winter daytime self-consumption of 0.5 kW.
- c. **Winter self-consumption also affects payback, but to a lesser extent.** Increasing average winter daytime self-consumption from 0.2 kW to 0.5 kW

reduces the payback period from around 30 years to approximately 19 years, when no buyback credits are received. The smaller effect reflects the lower level of solar generation during winter.

- d. **Buyback credits can significantly improve payback where summer self-consumption is relatively low.** At current buyback prices, the modelled payback period ranges from approximately 11 years at 0.1 kW average summer daytime self-consumption to around 8 years at 0.4 kW, assuming 0.5 kW average winter daytime self-consumption.
- e. **The future value of buyback credits is uncertain.** If summer buyback prices fall to zero, the improvement in payback associated with exporting excess generation is almost entirely lost. This raises a question about whether the additional cost of obtaining export credits, including metering and application costs, would provide sufficient future benefit if summer buyback prices decline as solar uptake increases.
- f. **Increasing self-consumption is important: energy storage could provide an alternative to exporting excess generation.** If buyback prices decline significantly, combining plug-in solar with energy storage—such as a battery or hot-water heating—could increase self-consumption. If summer self-consumption could effectively be increased to 0.6 kW and winter self-consumption to 0.8 kW, the model indicates a payback period of approximately 6–7 years, depending on the cost of the storage system.

Submission form (DG-related Code changes)

Please email your submission to: connection.feedback@ea.govt.nz by 5pm, Tuesday 6 October 2026

Name	Dr Kannan Munisamy Engineering and Technical Lead
Organisation	EEA

Questions on distributed generation-related Code change proposals

Questions	Comments
Q30. Do you agree the Code should be amended so the 10kW default export limit also applies to Part 1 applications? Please explain your views.	We agree the Code should be amended so the 10kW default export limit also applies to Part 1 applications. It makes sense to have consistency of export limit between Part 1 and Part 1A for the reasons outlined in the issues and consultation paper.
Q31. Do you agree the Code should be amended so that distributors cannot limit their approved inverter lists to only communicating smart inverters or use their COPS to mandate smart inverters or flexible/dynamic export limits? Please explain your views.	We agree the Code should be amended so that distributors cannot limit their approved inverter lists to only communicating smart inverters or use their COPS to mandate smart inverters or flexible/dynamic export limits. We believe that limiting approved inverter lists to only communicating smart inverters unreasonably restricts consumer choice and imposes additional costs on consumers wishing to install solar PV systems. 5.22 (a)-(d) also gives reasons why such inverters should not be mandated at this stage. 5.26 states: "This is evident as distributors are not yet widely implementing flexible/dynamic limits yet are complying with the 10 kW default export limit for small-scale DG. This suggests that networks currently have sufficient capacity to offer the default 10 kW static limit generally and do not currently need to mandate flexible/dynamic limits." We do not necessarily agree with this statement, as calculation of congestion at existing penetration levels (as required) invariably does not show constraints, yet at expected future penetration levels constraints are shown.
Q32. Do you agree the Code should be amended to allow distributors to 'build in' an extra 10% DG penetration when doing a network study, that may lead to parts of networks qualifying for export limits below 10kW? Please explain your views.	We cannot answer this question because the consultation document is unclear on what the 10% buffer actually is. In the title 3 on p.33 it refers to "...a buffer of 10% extra DG penetration...". Section 5.49 of the issues and consultation paper is consistent with this. However, in the example given in 5.50 of the issues and consultation paper it suggests that capacity of existing DG can be increased by 10% from 20 kW to 22 kW. This is not the same as increasing the penetration level by 10%. Instead, it is an increase in capacity by 10%. We note that network studies show that adding new PV at ICPs currently without PV into a low voltage network can have a large effect on voltage profiles in the low voltage network, and even conductor loading, depending on where the ICPs are located and their phase connection. Simply increasing the export allowance of existing ICPs is not equivalent to adding new PV at ICPs currently without PV.

	As an example, our interpretation of increasing the penetration level by 10% is as follows: - A low voltage circuit has 80 ICPs and an existing penetration level of 5% (4 ICPs have PV installed). - Depending on whether the buffer is multiplicative (as suggested in 5.50, even though that is not penetration level) or additive (as might be interpreted by 5.49) this would increase the penetration level to either 5.2% (the multiplicative case, resulting in 4.16 ICPs) or 15% (the additive case, resulting in 12 ICPs). - The former is so small as to be of no value, while the latter does have some value. In general, requiring distributors to only consider existing penetration levels when setting export limits will, in many cases, signal that high levels of export are permitted. In the majority of cases, penetration levels are currently so low that most export limits are 10 kW. Allowing applications of 10 kW export will: (a) use up network capacity, which may impact future DG export limits (i.e. disadvantage future applicants), and (b) require regular running of the ELAM as indicated in the issues and consultation paper. Furthermore, we believe that setting a lower export limit based on a future penetration level signals to DG owners to invest in self-consumption. Ideally, in combination with time-of-use prices, this would involve storing energy in the middle of the day for release during evening and morning peak periods, thereby reducing peak demand on networks (critical to support electrification and where housing density is increasing), avoiding much of the need for network capacity upgrades. This would ensure capacity for future PV applications and ideally lower costs to all consumers. The work by the Ministry of Business, Innovation, and Employment (Modelling the impacts of high solar and battery uptake on the electricity market) demonstrated this.
Q33. Do you agree that a 10% allowance (as an interim measure) reduces the need for frequent network assessment. If not, what alternative level of allowance or approach should the Authority consider and why?	We cannot definitively answer this question, as the application of the 10% allowance is unclear. See our response to Q32.
Q34. Do you agree the Code should be amended to explicitly require distributors to offer both Part 1A and Part 1 DG application processes? Please explain your views.	We agree that distributors should offer both Part 1A and Part 1. Offering Part 1A is important in terms of lowering cost for PV applications (both in a faster application process and lower fee) and automatically gaining important protection and voltage setting functionality in an inverter. Ultimately, it should be installers who understand and decide which part is appropriate to use for any given application for their customers. If the Code is changed to explicitly require distributors to offer both Part 1A and Part 1, some information targeted at installers and the rights of their customers may be of value.
Q35. Do you agree the Code should be amended to make it clear distributors cannot extend timeframes for Part 1A applications, but should not be penalised by the time taken by the applicant to remedy a deficient application? Please explain your views.	Yes, this seems reasonable.
Q36. Do you agree with the objectives of the proposed amendments? If not, why not?	We agree with the objectives of the proposed amendments. However, while the objectives set out to reduce the need for conducting frequent network assessments (6.1(c)), this may not be achieved, depending on what the buffer is, which is unclear.

	We note that conducting network assessments is a complex and resource intensive process.
Q37. Do you agree the benefits of the proposed amendments outweigh their costs?	Generally this is the case. However, if distributors can only set export limits based on existing penetration levels, high PV uptake with 10 kW export could occur and lead to network constraints. This in turn may require network upgrades. The cost in this case is very likely to outweigh any benefit of this amendment / existing requirement. In addition, no benefit from encouraging greater levels of self-consumption has been assessed. There is an inherent risk that 10 kW export limits (which as noted will largely be the case at existing penetration levels) sets a precedent with consumers that 10 kW export will always be permitted. In combination with existing buyback rates, consumers may perceive this as an opportunity to make more income from their PV systems. There is evidence that some residential consumers are expanding their PV systems with this in mind, without considering how buyback rates may change in the future. We believe that there is a duty to inform consumers of the risks of such activity.
Q38. Do you have any feedback on the Authority's assessment of the costs and benefits and the balancing of these as set out in this paper, including any evidence of quantified costs and benefits?	No comment other than that above.
Q39. Do you agree the proposed amendments are 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 cannot agree to the 10% buffer for the reasons given in our comments on Q32. Our preferred option is to allow distributors to determine export limits based on a future penetration level they see as reasonable, but capped at 35% for now. Otherwise, the ability for distributors to plan their network effectively is removed from them.
Q40. Do you agree the Authority's proposed amendments comply with section 32(1) of the Act?	No comment
Q41. Do you have any comments on the drafting of the proposed amendments?	No comment