Common Quality Issues
Electricity Authority
Via email
@ea.govt.nz

20 August 2024

Consultation Paper – Addressing more frequency variability in New Zealand's power system

Thank you for the opportunity to submit on the consultation paper "Addressing more frequency variability in New Zealand's power system" (Consultation). We have answered the Authority's specific questions in the attached Appendix A and have some broader comments that we set out below.

Mercury supports the Authority's wider review of the common quality requirements in part 8 of the Code and agrees that now is an appropriate time to be reviewing current arrangements in relation to frequency, voltage and harmonics. We have also submitted responses to the voltage and harmonics consultation papers.

Frequency keeping systems in New Zealand are not broken, simply require greater oversight

In relation to this Consultation, we have a high-level view that the current frequency keeping system in New Zealand is not broken. For Mercury, the status quo enables us to provide a sizeable portion (perhaps the majority) of the frequency and governor response required for New Zealand's power system.

The Code already requires generators to make the maximum possible injection contribution to maintaining frequency within the normal frequency band and to agree settings with the System Operator.[1] The System Operator therefore already has the tools to ensure that governor settings are maintained without the need for mandating specific settings (such as deadbands). Mercury supports more participants contributing to the stability of the power system but are not convinced that radical change is required to make this happen. The solution may be as simple as better oversight of the frequency response of generators connecting to the system by the System Operator.

Please don't hesitate to contact me at [redacted] or on [redacted] if there is anything contained in our submission that you would like to discuss further.

Yours sincerely

Jo Christie
Regulatory Strategist

[1] Electricity Industry Participation Code 2010 clause 8.17 (Make the maximum possible injection contribution) and Schedule 8.3 Technical Code A clause 5(1)(d) (Agree settings with the system operator)

Appendix A: Mercury Submission

Question	Comments
Q1. Do you agree the Authority should be short listing for further investigation the first frequency related option to help address Issue 1? If you disagree, please explain why?	Yes. While Mercury is not directly impacted by this potential change if the Authority is minded to reduce the threshold we would recommend reducing the threshold to 10MW rather than 5MW as the performance benefits for a 10MW threshold appear to be only marginally lower and this would align with the threshold for a generator becoming a market generator and being required to submit offers under the Code.
Q.2 What do you consider to be the main benefits and costs associated with the first frequency-related option?	Although no cost benefit analysis has been provided our view is the cost of compliance at the lower 5MW end of the threshold for smaller generating units would outweigh the benefits. There are costs associated with providing governor response – studies to ensure that plant is stable, the governors themselves, commissioning and testing governor performance, wear and tear. The studies appear to show little difference in system performance between 5 and 10 MW.
Q3. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if the threshold were to be lowered to 5MW or 10MW?	To reduce costs for small generators a less stringent compliance regime could be put in place where generators below the threshold are encouraged but not mandated to operate with frequency performance consistent with the Code.
Q4. What do you consider to be the pros and cons of aligning the AS/NZS 4777.2 standard with the Code requirement for generating stations to ride through an underfrequency event for six seconds?	We agree that the Authority should look align inverter standard AS/NZS 4777.2 with desirable frequency behaviour in the Code. We note that small inverters already total more than the largest generator on the system. Small scale solar currently contributes 400MW to the electricity system and this figure is growing by 10MW per month.[2] Transpower's assumption that rooftop solar generation will only reach 600MW by 2030 is therefore unlikely to hold true. The Authority could also consider how it might leverage emerging technology (such as EVs) to provide some of the frequency response traditionally provided by generators. For example, there would be little impact on consumers if EV charging rates were slightly reduced to provide a frequency response. We note that this is likely to require collaboration across many jurisdictions, due to the global nature of vehicle supply.

[2] Forsyth Barr Power Points July 2024 and https://www.emi.ea.govt.nz/Retail/Reports/GUEHMT?DateFrom=20130901&DateTo=20240630&Capacity=All_Total&FuelType=solar_all&Show=Capacity&_rsdr=ALL&_si=v|3

Q5. Do you consider a permitted maximum dead band should be based on the technology of the generating station? Please give reasons with your answer.	Whilst Mercury does not favour the option of mandated deadbands, we would have a strong preference for a maximum permitted deadband based on the technology of the generating station if this were implemented. As shown in the Transpower analysis there is a significant difference in the frequency response implemented by different technologies and represents a measure of the costs faced by differing technologies in providing the service. From an overall system cost point of view the service should be provided by those who are able to provide it at lowest cost. Under a previous proposal to address governor performance in the normal frequency band[3] work was done to show that the costs to some technology would be magnitudes greater than the costs to others. Mercury notes that if technology bands were to be implemented, this may need to be nuanced. For example, within hydro technologies there might be a case for Kaplan turbines to have a wider deadband than Francis turbines due to more moving parts in the turbine that respond to governor action and are difficult to maintain.
Q6. Do you consider the Authority should be short listing the widening of the normal band for frequency as an option to help address the identified frequency-related issue? Please give reasons with your answer.	No, Mercury does not believe there is merit in widening the normal frequency band at this time. We are of the view that a need for increases in frequency keeping will not eventuate as quickly as Transpower analysis suggests. A number of assumptions in the Transpower analysis appear to be conservative, effectively assuming a high degree of correlation of deviations in the frequency keeping timeframe between wind (and solar) farms, which we do not believe will eventuate to this degree.

[3] https://eacorpsitelegacy.z8.web.core.windows.net/assets/dms-assets/18/18134Normal-Frequency-AOPO-Consultation-Paper.pdf and Electricity Authority, 18 November 2014, Normal frequency asset owner performance obligations, Consultation Response Paper, Appendix A.

Q7. Do you agree the Authority should be short listing the second frequency-related option to help address Issue 1? If you disagree, please explain why.	Mercury urges caution if the Authority chooses to pursue the second frequency related option of setting a maximum deadband beyond which a generator must contribute to frequency keeping and instantaneous reserves. Mandating a maximum deadband will result in more wear and tear / more spilt energy / reduced efficiency on units with reduced deadbands) therefore increased maintenance/fuel/spill costs. If a 0.1 Hz deadband were to be mandated this is likely to present significant issues for some existing plant, particularly geothermal, as this would have implications for steam (and binary fluid) system design and control. It is not clear whether the proposal for 0.1 Hz would apply for all generation or just new generation. If the proposal will apply to all generation then there would need to be a reasonable phase in period and simplified testing/submission requirements as there is limited resource to implement governor changes and test. We note that when Australia's NEM issued changes there were more relaxed testing requirements than normal during the phase in period. We don't consider that the existing system is "broken". There are existing requirements in the Code for generators to make the maximum possible contribution to maintaining frequency within the normal frequency band and to agree settings with the System Operator. In our view, this gives the System Operator the necessary tools to ensure that governor settings are maintained for the system as a whole while also taking into account the naunces of specific technologies without the need for mandating specific settings such as deadbands.
Q8. What do you consider to be the main benefits and costs associated with the second frequency-related option?	The costs to generators of mandating a maximum deadband would be significant. Some technologies (geothermal, wind, solar) will face energy loss (some "spill" within the normal frequency band), while for some technologies implementing an effective 0.1 Hz deadband is likely to be complex due to plant interactions. Implementing governor response on geothermal units would be difficult and expensive. There is inherent deadband in all geothermal units but no applied governor deadband settings. The units operate at 100% baseload with governor valves 100% open. If an effective deadband of 0.1 Hz was mandated, geothermal plant would run at 100% normally but would reduce output if the frequency exceeded 50.1 Hz. This momentary reduction in output would create problems for existing and new plant, with implications for steam, binary fluid, system design and control, all impacting compliance costs, fuel costs and creating reduced efficiencies.
Q9. What costs are likely to arise for the owners of generating units if a permitted maximum dead band were to be mandated in the Code that was not less than the inherent dead band in generating units?	There would be a loss of energy from generators that have a use it or lose it fuel sources (geothermal, wind and solar).

Q10. What do you consider to be the main benefits and costs associated with the third frequency-related option?	The status quo is known and the quantities can be adjusted as the need is demonstrated. We would urge such changes to quantities to be made after the need is demonstrated in real system behaviour rather than theoretical studies. As noted in our response to Q6 a number of studies appear to have conservative assumptions. Further we would recommend the Authority: • Ensure that there are low barriers to entry (e.g. ensure that there are no market barriers to batteries supplying FK while charging as well as discharging); and • Continue to monitor FK requirements and whether a flat FK band requirement is appropriate for all time periods. For example, more FK might be required during morning and evening load and solar ramps, while lesser quantities may be required when these are relatively constant.
Q11. Do you have any comments on the Authority's assessment of options to help address Issue 1 identified in our 2023 Issues paper?	We make the following additional comments: Aspects of the code around frequency response are written in a technology specific manner i.e. "speed governor." This means that technologies such as wind, solar, batteries must apply for equivalences even though they provide the same system performance. • Although not directly related to frequency, we note that many hydro units are able to operate in synchronous condenser mode (also call tail water depressed or TWD). The units are typically run is this mode to provide reserves or voltage support, but while in this mode are also capable of contributing to system inertia and system strength. While the System Operator is able to call on some units to operate in this mode under certain circumstances (for example under a voltage support arrangement), with the change in system conditions (some of which may arise unexpectedly) we consider it prudent to consider widening the criteria under which the System Operator (with the appropriate agreement of and compensation to asset owners) is able to call on units to run in synchronous condenser mode. • Allocation of FK costs can be problematic. In other jurisdictions complex methods of allocating costs has seen the rise of sophisticated methods to reduce their cost allocation without actually reducing the overall system costs. We recommend keeping cost allocation simple to avoid such unintended consequences.

Common Quality Issues
Electricity Authority
Via email
fsr@ea.govt.nz

20 August 2024

Consultation Paper – The governance and management of harmonics in New Zealand's power system

Thank you for the opportunity to submit on "The governance and management of harmonics in New Zealand's power system."

Harmonics is a complex issue with many interactions. We consider that one of the main challenges facing the sector is the lack of available data available on the harmonics that exist on the New Zealand power system. It is very difficult to make informed decisions in an information vacuum, and in Mercury's view the Authority's priority should be to ensure that harmonics are measured at key, and the resulting information shared so that the existing state of harmonics on the New Zealand power system is properly understood. Only then, can solutions be properly developed to address problems (if they exist).

As an indication of how complex this problem is we have shared some of Mercury's experience with harmonics below:

1. Harmonics exist on all power systems so we should not focus on inverter-based generation

Harmonics exist on all power systems. While inverter-based resources have different harmonic characteristics, synchronous generators also have harmonic characteristics and are not free from harmonics. Therefore, with a rise in inverter-based generation, characteristics may change, but harmonics are not a new issue. In this vein, we consider that narratives that unduly focus on inverter-based generation are unhelpful. (For example, Figure 2 in the consultation document prima facie shows harmonics generated by a wind farm, whereas the report from which the figure is sourced notes that "much of the harmonic distortion is incoherent and effectively cancelling itself out" to the extent that harmonic standards are suggested to be simplified).

2. Mitigation should not be installed based on pre commissioning modelling

Harmonic modelling is very complex and is often conservative, so that post commissioning measurements can be significantly different to pre commissioning modelling. Installing mitigation based on pre commissioning modelling is therefore likely to result in wasted investment, which may in fact make further harmonics modelling and mitigation more complex (for example, harmonic filters alter resonance points affecting the surrounding networks). We consider that filters should not be installed pre-emptively and only where there is a demonstrated need.

3. The root cause of harmonics is very difficult to identify

Analysing the source of harmonics even where they are detected can be extremely difficult due to the constantly changing dynamics of the system as different loads, circuits and generators connect, disconnect and change their output. Even where clear daily patterns of problematic harmonics are observed, the root cause could still be very difficult to identify and be unrelated to the apparently obvious change in the system, such as the commissioning of a wind farm.

We would welcome the opportunity to share our technical experiences with the Authority in more detail. Please contact me at [redacted] or on [redacted] if you would like to arrange a conversation with our engineers.

Yours sincerely

Jo Christie
Regulatory Strategist

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Via email
fsr@ea.govt.nz

20 August 2024

Consultation Paper – Addressing larger voltage deviations and network performance issues in New Zealand's power system

Thank you for the opportunity to submit on the consultation paper "Addressing larger voltage deviations and network performance issues in New Zealand's power system" (Consultation). Our response to the Authority's specific questions are attached at Appendix A and we have set out our core views for consideration below.

Biggest issue is power factor obligations on distributors

One of the biggest issues that we face when embedding generation (particularly deeply embedded generation) are the power factor obligations on distributors. This is a significant impediment to these projects. In our view the present arrangements are likely to result in perverse outcomes. We strongly agree with paragraphs 5.8 and 5.9 in the consultation document that the current arrangements are no longer fit for purpose and should be changed. In our view the current arrangements are incompatible with proposals to provide voltage support from embedded generators.

Reactive power allowance would be a better measure

We do not consider power factor as a useful measure for future arrangements and instead believe that a reactive power allowance based on the maximum MW through the connection would be a more appropriate. Care would need to be taken in the drafting so that the updated arrangements are not more onerous than necessary in order to avoid unnecessary costs on distributors and embedded generators. We would also support these requirements being moved from the Benchmark Agreement and the Connection Code, into the main Code so that they can be subject to the same dispensation arrangements as other Asset Owner Performance Obligations.

Additional comments not covered by the Consultation questions:

1. Obligations should apply to new generating stations and energy storage systems only

The Authority proposes that the new requirements referred to throughout the Consultation should apply to new **and existing** generating and energy storage systems. Mercury recommends these requirements should apply to new generating and energy storage systems only. Many stations will not be able to physically comply with new voltage obligations, for example small hydro stations and old wind farms using induction machines. These stations are not currently causing major system issues, so it is almost certain that they will be eligible for dispensations under the Code. Any proposal to place obligations on existing plant will create significant avoidable workload for asset owners and the System Operator (SO) in evaluating compliance, applying for and granting dispensations, with likely little actual benefit.

2. No reactive dispatch signals to embedded generators

The issue identified at paragraph 4.32(d) of the Consultation is a serious one. We do not think the SO should be sending reactive dispatch signals to embedded generators without careful consideration, particularly if these are MVAr rather than voltage dispatch signals. This will alter voltages on distribution networks to which SO will likely have little visibility, particularly parts on the distribution network electrically distant from the GXP. Distribution networks have much higher impedances which means that they are much more sensitive to reactive power flows than transmission networks, while the voltage tolerances are tighter as they are closer to customers, so any setpoint changes will need to be carefully considered to avoid adverse effects on customers or parts of the distribution network being pushed out of allowable ranges.

3. Transpower should be responsible for data dissemination

We do not think the operational coordination suggested at paragraph 4.22 and discussed again in section 5 requiring embedded generators to create links to both Transpower and the local distributor is practically achievable. For ICT security reasons we deliberately do not connect communications networks on site. Since we already send this data to Transpower, we suggest it would be more feasible and efficient for Transpower to forward the data to the relevant distributor.

4. Technology specific wording should be removed from the Code and replaced with more technology neutral terms.

There are a number of terms in the code that use terms that are specific to synchronous generator technology such as “excitation systems” which we believe should be replaced with technology neutral terminology.

We would be happy to discuss any of the views we have shared in our submission in more detail. Please don’t hesitate to contact me at [redacted] or on [redacted]

Yours sincerely

Jo Christie
Regulatory Strategist

Appendix A: Mercury Submission

Question	Comment
Q1. Do you consider it likely that distributors will, in the absence of a Code requirement, place voltage support obligations on some or all generating stations and energy storage systems (when discharging) that connect to their networks? Please give reasons for your answer.	The present arrangements are an impediment to sensible voltage support arrangements. In our experience present arrangements focus on maintaining distributors' ability to maintain compliance with the power factor obligations in the Connection Code. Until this requirement is softened, in our view there is very little scope to provide voltage support to address other issues.
Q2. Do you agree generating stations and energy storage systems connected to local distribution networks at the GXP voltage (which varies by local distribution network) should be required to support voltage, or do you consider the obligation should be placed on generating stations and energy storage systems connected at a uniform voltage (eg, 33kV)? Please give reasons for your answer.	Yes, with caveats. Mercury does not agree that meaningful reactive support obligations can be pushed down to lower levels than the GXP voltage without careful consideration of how the voltage support will interact with the network companies' existing voltage control systems. Even at the GXP voltage level, in many (perhaps most) cases the effective reactive support able to be provided will be limited by the impedance between the generator and the GXP (along with factors such as allowable voltage limits/steps).
Q3. Do you consider there should be a capacity threshold (eg, a nominal net export or nameplate capacity of 5MW or 10MW) for generating stations and energy storage systems connected to local distribution networks to support voltage? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	If the Authority is minded to reduce the capacity threshold we consider that the threshold should be no lower than 10 MW until it is clearly evident that a lower threshold is required. The 10 MW aligns with a number of existing requirements (for example around offers) and it is likely that there is significantly decreasing benefit with decreasing size.
Q4. What do you consider to be the pros and cons of requiring generating stations / energy storage systems connected to local distribution networks to have a reactive power range of ±33% rather than the +50%/-33% range specified in clause 8.23 of the Code?	Mercury does not support the +50%/-33% range and in our view even +/-33% is likely to result in capacity that is not practically useable in many locations (impedance will be too high to allow the full range to be used without pushing voltages out of limits). A +50%/-33% range is unlikely to be usable in all but the most favourable of circumstances so will just be adding cost without any tangible benefits. Care will need to be taken around the wording of where compliance is measured as this is a point of ambiguity in the existing code.

Q5. Do you agree the Authority should be short listing the first voltage-related option to help Addressing larger voltage deviations and network performance issues in New Zealand's power system 45 address Issues 2 and 3? If you disagree, please explain why.	Yes, with the reservations expressed above.
Q6. What do you consider to be the main benefits and costs associated with the first voltage-related option?	None of the benefits can be realised without changes to the power factor requirements on distributors in the Connection Code. A sensible arrangement for reactive support/voltage control in conjunction with reasonable requirements for reactive power flows at GXPs will enable generation to be accommodated on distribution networks while maintaining acceptable voltages and reactive power flows.
Q7. Under the first voltage-related option, what costs are likely to arise for the owners of distributed generation, embedded generating stations, and energy storage systems with a point of connection to the local distribution network?	Actual equipment cost impacts are likely to be low with a +/-33% requirement (depending on where this is measured) as most equipment comes with approximately this capability. Equipment costs will be higher with a +50% requirement, as this is not typical. There will be costs associated with establishing communications and control systems as well as for studies to ensure that voltage controls interact correctly. Consideration should be given to simplifying the study requirements for smaller generators so that these are not overly onerous. n
Q8. Under the first voltage-related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?	The suggested amendment to clause 8.22 requires that existing and new generating and energy storage systems provide voltage support when discharging, charging and idle. We query the requirement to provide voltage support while idle as this would force battery owners to keep inverters running (with resultant costs and losses) to provide "free" voltage support (noting that these losses incur transmission as well as energy charges). This would be analogous to preventing generators from switching off hydro units and being forced to keep them running in synchronous condenser mode when not generating. Batteries may be idle up to 80% of the time so additional losses to keep inverters running are much more significant than other forms of generation. We recommend this clause be amended to read "discharging, charging or dispatched to provide an ancillary service."

Q9. Do you agree the Authority should be short listing the second voltage-related option to help address Issues 2 and 3? If you disagree, please explain why.	In our view Option 2 is essential if Option 1 is proceeded with. We strongly agree with the Authority's statements in paragraphs 5.8 and 5.9 of the consultation document. In our view the current power factor obligations on distributors are no longer fit for purpose and are already an impediment to embedded generation – particularly generation which is remote from the GXP. Changes in this area are key to enabling deeply embedded generation to be connected in a cost-effective manner. We support the second voltage related option with the following recommended changes: > The Schedule 12.6 requirements referred to at paragraph 5.1(c) should be moved from the transmission agreement template and bought into the main sections of the Code so that distributors voltage support obligations are subject to the same dispensation arrangements as other asset owner performance obligations (AOPOs). > The proposed power factor referred to at paragraph 5.1(c)(ii)is not a useful measure where there are two way power flows. When local generation matches local supply, power factor will go to zero, making any power factor obligation greater than zero impossible to achieve. We recommend this obligation be framed in a similar way to the generator obligations (MVAr within a +/- 33% range of maximum GXP MW demand). Some insight as to what limits might be reasonable may be able to be gained by interrogating the simulations that Transpower did to inform the consultation and looking at the active and reactive power flows at the GXPs. > The proposed framing of the requirement suggests that distributors have to be able to be operate at a power factor of 0.95 leading. Currently, distributors are only required to install assets to achieve unity (upper parts of both islands) or better than 0.95 lagging (rest of the country). This proposal would require distributors to make significant investments in additional voltage support assets – which we don't think is the intention here.
Q10. What do you consider to be the main benefits and costs associated with the second voltage-related option?	Provided that the requirements are framed in terms of reactive power flows and not power factor, and that obligations are open to the dispensation regime we believe there will be benefits in terms of being able to accommodate additional embedded generation without the need for excessive reactive power compensation equipment. In our view equipment should be designed and operated to best meet power system needs rather than for compliance with arbitrary requirements.
Q11. Under the second voltage related option, what costs are likely to arise for the owners of energy storage systems with a point of connection to the transmission network?	The +50% requirement is likely to impose additional cost as this is outside the range that is normally offered by equipment suppliers. As long as the dispensation regime remains unchanged this should not represent a significant cost barrier and puts energy storage systems on a level playing field with other forms of generation.

Q12. Do you consider it likely that distributors will, in the absence of a Code requirement, place fault ride through obligations on some or all <30MW generating stations that connect to their networks? Please give reasons for your answer.	We have no view on this but note that a number of distributors already do either by calling relevant standards or requiring studies.
Q13. Do you consider it appropriate to include in the Code fault ride through curves for generating stations connected to a local distribution network at a nominal voltage equal to the GXP voltage, which take into account network Addressing larger voltage deviations and network performance issues in New Zealand's power system 46 protection considerations? Please give reasons for your answer.	In general, we think that from a system point of view it is preferable that as much generation plant as practical is capable of fault ride through in order to ensure that the effects of faults are kept as confined as possible. This is complicated at the distribution level due to conflicting requirements around anti-islanding along with long fault clearance times. We are not convinced that the best place for this is the Code or via other mechanisms such as equipment Codes.
Q14. Do you consider there should be a threshold based on connection voltage and capacity (eg, a nameplate capacity or nominal net export of 5MW or 10MW) for generating stations connected to distribution networks to ride through faults? Please give reasons for your answer, including any implications of having / not having a capacity threshold.	Mercury would support a threshold based on connection voltage and capacity however in our view the main issue is one of demonstrating compliance. The same inverters/wind turbines will be used on a 10 MW solar/wind farm/BESS as they will be on a 30+MW solar/wind/BESS. The existing regime requires months of work by specialists running 1000s of fault simulations. This is time (~3 months), financial and specialist resource intensive. If fault ride through (FTR) is going to be bought in for smaller generators, then the compliance regime for generators <30 MW should be made much simpler. For example, below a certain threshold (e.g. 10 MW), the requirement could simply be that a generator's FRT specifications must not conflict with the FRT obligations in the code, while for somewhat larger generators (for example 10 – 30 MW) a simplified compliance regime using SMIB (single machine infinite bus) rather than full network modelling is appropriate in our view. As mentioned in our covering letter, we recommend any new FRT requirement should only apply to new generating stations. As an aside it appears to us that there is a trend for FRT compliance studies in general to have become more onerous over time and it may be appropriate to review whether a more streamlined approach is possible.
Q15. Do you agree the Authority should be short listing for further investigation the third voltage-related option to help address Issue 4? If you disagree, please explain why.	Yes, but with caveats. Demonstrating compliance using the current methodology is too onerous to be applied to small generators, in our view.
Q16. What do you consider to be the main benefits and costs associated with the third voltage-related option?	There are system benefits (limiting the amount of generation tripped in a fault), but we have concerns about demonstrating compliance under the current regime as discussed above.

Q17. What costs are likely to arise for the owners of (single site and virtual) generating stations under the 30MW threshold if these generating stations must comply with the fault ride through AOPOs because they are connected to a distribution network at a nominal voltage equal to the GXP voltage?	See above. If this were to apply to virtual stations this would further complicate the modelling required to demonstrate compliance if the compliance regime is not changed.
Q18. Do you have any comments on the Authority's assessment of options to help address Issues 2, 3 and 4 identified in our 2023 Issues paper?	The Authority should consider the role of increasing amounts of distributed energy resources installed at the consumer level. It should ensure that appropriate standards (e.g. AS 4777) are developed with settings appropriate for the New Zealand power system for items such as solar, battery and EV charging system.