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Electricity Authority
**By email:** submissions@ea.govt.nz

# Market enhancement omnibus

Genesis Energy Limited (**Genesis**) welcomes the opportunity to provide a submission to the Electricity Authority (the **Authority**) on the consultation paper *Market enhancement omnibus* (the **consultation paper**) dated September 2018.

Broadly, we support the Authority to engage with industry in an omnibus format, but we do note this requires participants to consider a range of issues, some of which are intrinsically linked; others entirely unrelated, concurrently. This can put a strain on resources, particularly when there are other industry consultation processes underway. This may limit the quality of engagement, and we encourage the Authority to be mindful of this when planning for its next omnibus.

In our responses on the *Switch process review* section we commented that a number of the issues raised are related and should not be resolved in isolation so as to avoid unintended consequences. We also note that many of the issues in this section have arisen as the competitive market has developed to offer increasingly differentiated, innovate products and services for the benefit of consumers.

In our view, and that of the Switch Technical Working Group (**STWG**), the switch process needs a holistic re-think to both resolve these issues, and provide for further industry change. This is consistent with the Authority's role as regulator to ensure the regulatory framework can strike the right balance between allowing innovation to develop within the bounds of existing rules, and responding when market failures are identified.

We have provided comments in the appendices attached on the *Access to WITS and the registry, Switch process review, Integrating hosting capacity into Part 6 for low voltage networks*, and *Review of metering and related registry processes* sections of the consultation paper. We note that for the questions relating to access to WITS, we are comfortable with the proposed changes in principle, subject to legal review. If you would like to discuss any of these matters further, please contact me by email: margie.mccrone@genesisenergy.co.nz or by phone: 09 951 9272.

Yours sincerely

Margie McCrone
Senior Advisor, Government Relations and Regulation

# Appendix A: Access to WITS and the registry

| QUESTION | COMMENT |
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| Q1: Do you agree that compromising the operation of WITS or the registry could have serious implications for the efficient operation of the New Zealand electricity market? If you disagree, please provide reasons. | Yes.[1] That said, the consultation paper does not appear to consider that the registry has a fast switch over disaster recovery that would limit any operational outage that would have implications for the market. |
| Q6: Do you agree with our proposal to amend the regulation of access to the registry? If you disagree, please provide reasons. | Yes. |
| Q7: Do you agree with the proposed improvements to the drafting of clause 11.28? If you disagree, please provide reasons. | No, as per the following comments and *suggested amendments*:<br><br>**The Code**<br><br>(2)(b) We are concerned there is no protection for a participant against being unjustifiably suspended, or any avenue to dispute outcome. This should be addressed.<br><br>(2AA) We are concerned that the current drafting of the section allows the Authority to make unilateral changes to a system that is central to industry compliance that may result in unreasonable costs to businesses, which will ultimately be paid by consumers. The Authority should be required to consult on any proposed changes; the wording could read, '…from time to time, *and after consultation*…'<br><br>**The Policy**<br><br>2. 'The registry facilitates *ICP* switching and reconciliation…'<br>2.1 'The registry is a…mechanism for processing the switching of *ICPs* between *traders*…' [2]<br><br>2.5 and 4.2(iii) appear to be in conflict as one of the purposes of connection data API is to supply information to present offers to customers. The intent of these clauses should be clarified. |

[1] As per the cover letter, we support proposed changes to WITS access in principle, but this is subject to legal review.
[2] We note the role of the registry is to switch ICPs, not customers. This is an important distinction that is in fact called out in the Switch Process Review section of the consultation paper.

# Appendix B: Switch process review

| QUESTION | COMMENT |
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| Q1: Which, if any, of the 22 issues raised in this paper do you consider should not be investigated further? Please give reasons. | In our view, many of the issues raised are interlinked so we do not believe that they should be resolved independently or there could be unintended consequences. Where we believe there is an interconnection between issues, *we have indicated so*. |
| Q2: Are there any issues not raised in this paper that you consider should be investigated? Please identify these other issues and give reasons why they should be investigated. | A number of the issues raised are caused by parts of the industry changing faster than others and we consider the current switching process needs a holistic re-think to:<br>a) resolve issues created by increasing differentiation and innovation among participants; and<br>b) future-proof the process for a future where there are multiple services offered to a single ICP.<br>This was also identified by the STWG. |
| **Issue #1**<br>*This relates to issues 2 and 10* | |
| Q3: How material is this issue? | Genesis is not aware of any evidence that this issue is widespread. In the year to 30 June 2018, our average switch time was 2-3 days and there was high compliance with the 10-day rule: we processed 37,592 TR losses, none of which exceeded 10 days; 956 exceeded 5 days. We also processed 28,609 gains, of which 34 exceeded 10 days; 717 exceeded 5 days.<br><br>In our view, the real issue is that the date of the switch is determined by the losing trader. This removes the ability for the gaining trader to align ICP ownership with any commercial arrangement made with the customer e.g. necessary metering changes or commencement of products and services.<br><br>We suggest that the process should be changed so that the gaining trader can elect to provide the switch date. The gaining trader would need to operate within specified parameters so as to avoid any valid restrictions. |
| Q4: Is this issue getting worse? | |

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| | As per the consultation paper, the issue has been observed, at consistent levels, since the 5/10-day rule was introduced.<br><br>Demand to have the gaining trader determine the switch date has grown as competition to create more differentiation in products has increased. |
| Q5: Why do you think this issue is occurring? | Traditional determination of the switch date process has been made redundant by advances in customer offerings. |
| **Issue #2**<br>*This relates to issues 1 and 5* | |
| Q3: How material is this issue? | This issue is only material for traders that have an offering limited to a class of metering not currently installed at an ICP the trader wishes to gain, or traders that have limited system capability that is limited to handling data in certain formats.<br><br>We consider it can be resolved by the solution suggested above under issue #1, that is, allowing a gaining trader to set the switch date. |
| Q4: Is this issue getting worse? | The issue has worsened as new retailers have entered the market relying on access to mass market half hour (**HHR**) metering. It will improve as HHR deployments continue. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #3**<br>*This relates to issues 6 and 10* | |
| Q3: How material is this issue? | This issue only occurs when the losing trader uses non-half hour metering data (**NHH**) and the gaining trader requires HHR data. While the differences may be small, the frequency is likely a concern for these gaining traders.<br><br>As this issue only occurs when there is an advanced meter (**AMI**) at the ICP, in our view it can be resolved by having the meter equipment provider (**MEP**) determine and supply the switch event read to both parties via the registry and switch files. |
| Q4: Is this issue getting worse? | The frequency of occurrences will be directly related to the market activity of HHR gaining traders. |

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| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #4** | |
| Q3: How material is this issue? | In our view, traders should not be required to provide data [to facilitate an ICP switch] that is already stored in the registry and will not change as consequence of the switch.<br><br>We consider changing the switch process to allow automatic completion by the registry on solely unmetered ICPs is likely to be an efficiency gain overall, and will prevent any discrepancies between the losing trader’s data and the registry being passed on. |
| Q4: Is this issue getting worse? | It is static. |
| Q5: Why do you think this issue is occurring? | There is currently no differentiation in the process between metered and unmetered ICPs. |
| **Issue #5**<br>*This relates to issues 2 and 16* | |
| Q3: How material is this issue? | Genesis considers the timing of the delivery of data for a service agreed between a trader and an MEP should fall under the commercial arrangement agreed.<br><br>In our view, any mandated minimum delivery period may have perverse effects. |
| Q4: Is this issue getting worse? | We are unaware if this is the case. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #6**<br>*This relates to issues 3, 10, 12, 14 and 16* | |
| Q3: How material is this issue? | This issue results from instances of issue #3 described above and as such has the same solution.<br><br>We consider read time could be supplied in addition to switch event reads so that HHR gaining or losing |

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| | traders know what periods to begin or cease trading (respectively).[3] |
| Q4: Is this issue getting worse? | We consider this issue will get worse as more traders use HHR data. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #7** | |
| Q3: How material is this issue? | This is a common issue throughout industry that could be mitigated by having the switch request file include an indicator as to whether the ICP switch is a consequence of obtaining a new customer. |
| Q4: Is this issue getting worse? | We believe it is becoming more prevalent as focus on industry performance increases. |
| Q5: Why do you think this issue is occurring? | This has been an issue since switching began as a result of the process design. |
| **Issue #8**<br>*This relates to issue 10* | |
| Q3: How material is this issue? | Immaterial. This is an issue with reporting for the Authority that has little impact on industry participants; as such we do not consider changes to everyday processes and file formats would be justified to accommodate it.<br><br>It appears that reporting accuracy and awareness is the underlying concern for the Authority. To address this, advice of ICPs involved in a sale and the effective date (in a defined format to help reporting) could be mandated to be supplied outside of the ICP switch process as and when a sale or transfer occurs. |
| Q4: Is this issue getting worse? | No comment. |
| Q5: Why do you think this issue is occurring? | No comment. |
| **Issue #9**<br>*This relates to issues 1, 4 and 10* | |

[3] We note that timing differences are relevant in HHR/HHR switches as well as NHH/HHR switches.

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| Q3: How material is this issue? | We hear that anecdotally many traders send switch acknowledgment (**AN**) files for every switch as it is easier than including logic in their systems to only send the AN file when they must.<br><br>Over time the original purpose of an AN file - that is, to identify the current trader and supply information not held in the registry - has been superseded by developments in the registry to the point there is doubt it provides any value in the ICP switch process anymore.<br><br>In addition to the solution recommend above for issue #1, we consider the AN file should be removed from the switch process to simply it. |
| Q4: Is this issue getting worse? | It is static. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #10**<br>*This relates to issues 1, 3, 6, 8 and 9* | |
| Q3: How material is this issue? | Genesis agrees this is an issue and consider it could be resolved by removing the connection between transfer, move-in or half hour codes and subsequent switch timeframes: If the gaining trader can indicate whether they wish to complete the switch (say for non-mass market AMI ICPs), and if the gaining trader can set the switch date, this will mean there is a single timeframe for all switches to occur e.g. all switches to be completed within the latter of 2 business days of the event date or when the switch notification is received by the registry.<br><br>We consider this would be a customer centric move, as having the timeframe based on the switch event date means it is tied to a date the customer is aware of, rather than a date that is related to an internal file exchange protocol. The rider of the latter of event date or notification file date is to account for backdated switches such as historical move-ins.<br><br>If this change and others we have recommended above were implemented, we could sign up a customer today and agree to start billing them from 15th of the following month as that aligns with their pay cycle. We would submit a first notification file (**NT**) with the 15th as the switch date and by the 17th we would have the switch complete (**CS**) file with |

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| | metering configuration from the registry combined with a read for the 15th. |
| Q4: Is this issue getting worse? | It is static. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #11** | |
| Q3: How material is this issue? | Genesis does not consider this issue is material, and there is no justification for regulatory intervention at this time.<br><br>In our view, if information is required from a third party for a trader to complete their obligations, this is not a failing of the ICP switch process, but rather an issue for that participant's operational relationship with the third party and/or its own internal processes.<br><br>Altering the ICP switch process to 'address' delays is likely to have the effect of disguising the underlying issue – as happens currently with traders withdrawing switches where they have delays in creating the CS file and then re-processing the switch to avoid the CS file timeframe breaches. |
| Q4: Is this issue getting worse? | We note that soon after updates were made to Part 10 of the Code, several switches were delayed due to incorrect metering data being populated in the registry. These delays have dropped away as the data has been corrected and in absence of evidence to the contrary we believe the 'noise' around this issue is simply a hangover from that time. |
| Q5: Why do you think this issue is occurring? | It is a direct result of participants' own internal processes and third-party relationships. |
| **Issue #12**<br>*This relates to issue 6* | |
| Q3: How material is this issue? | It appears this issue results from a misunderstanding of the use of switch reads rather than any definition itself.[4] A real, associated issue is that with the NHH read being deemed to be at the 24:00/00:00 boundary, a gaining HHR retailer will notice a |

[4] The definitions are not incompatible: the NHH meter read definition spells out the period for which a NHH read covers, the switch event read definition makes it clear it is a boundary read i.e. a start read for gaining trader, not a consumption read for the first day of ownership.

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| | discrepancy between the 24:00 NHH read and the subsequent half hour consumptions as the NHH read is to be an estimate for 24:00. This issue is addressed via the existing NHH to HHR trader replacement read (**RR**) clauses. |
| Q4: Is this issue getting worse? | The confusion could be becoming more prevalent as more HHR traders emerge. |
| Q5: Why do you think this issue is occurring? | See response to Q2. |
| **Issue #13** | |
| Q3: How material is this issue? | Yes, this is a material issue that should be addressed. The most common outcome we observe is that the status on the registry becomes misaligned e.g. when the current trader disconnects the ICP just as sign up with a new trader occurs and the notification file is delivered to the registry before current trader's status event - 'ACTIVE' to 'INACTIVE' - is registered; the gaining trader reconnects the ICP as part of sign up but no update to registry is made as the status is 'ACTIVE'; then the switch completes and the losing trader resends their original status event leaving the registry status reading as 'INACTIVE'. |
| Q4: Is this issue getting worse? | It is static. |
| Q5: Why do you think this issue is occurring? | We believe it is the result of a rule to lock the ICP when a switch is in progress that has been around since the registry was established. While there were probably valid reasons for doing so at that time, it is timely to reconsider whether certain fields should be updateable during the switch process e.g. status and nominated MEP. |
| **Issue #16**<br>*This relates to issues 5 and 6* | |
| Q3: How material is this issue? | All the shortcomings identified in the paper present inefficiencies for parties involved. |
| Q4: Is this issue getting worse? | In our view it is likely more disconnects will happen as new retail business models emerge. There are two potential solutions we see: |

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| | a) amending the switch process to reduce the need for read adjustments; or<br>b) refining the RR process itself.<br><br>We consider that having MEPs provide switch reads on ICPs with AMI would dramatically reduce the number of RRs required. The shortcomings that have been identified can be resolved as follows:<br><br>1) this is not a shortcoming of the RR process but the reasoning for its existence;<br>2) a simple alteration can be made to make the 4-month period start from the CS file date, not the switch event date;<br>3) a reasonable ICP threshold should be introduced - in the times of only NHH metering, 200 kilowatt hours was determined to be appropriate as that roughly equated to the cost to parties of amending the reads and amounts less than that did not have significant impacts on a monthly bill. With the advent of HH and the associated greater resolution of consumption it may be timely to review this threshold;<br>4) a simple change to allow either party to initiate the read amendment could be made, and we note this currently happens in the sense a losing trader may advise the gaining trader they now have actual read and can request they initiate, however the gaining trader can legitimately refuse if it is to their disadvantage;<br>5) this is addressed by having MEPs supply switch read for AMI ICPs, as above; and<br>6) this is addressed if the MEP supplies a time stamped reading. It is our understanding that MEPs may refuse to supply pre-switch date data if there are additional costs and time involved as a result of their systems being configured to deliver consumption data to the trader of the ICP at the time of the consumption i.e. extracting back dated periods is an exception process for them. |
| Q5: Why do you think this issue is occurring? | We believe the initial drafting of the RR rules, which was during a time where there was only NHH billing, did not envisage the actual operational function of switching process. |
| **Issue #17** | |

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| Q3: How material is this issue? | This issue only occurs within one network area that does not always move from 'NEW' to 'READY' in a timely fashion. Having had discussions with them, it is clear they are aware of their obligations but are hindered by delays in the return of paperwork from their contractors. A bypass of this delay would be to allow traders to accept ownership of an ICP and update certain fields e.g. nominate an MEP while the ICP record is in 'NEW' status. |
| Q4: Is this issue getting worse? | No. It has improved over time. |
| Q5: Why do you think this issue is occurring? | This is a result of field processes not aligning directly with Code requirements. |

# Appendix C: Integrating hosting capacity into Part 6 for low voltage networks

| QUESTION | COMMENT |
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| Q1: Have we adequately outlined the issues with increasing levels of SSDG, particularly inverter-connected solar PV systems? | Yes. |
| Q2: What other factors are relevant to these technical network considerations? | Genesis considers that a lack of investment in technology to monitor the effects of small-scale distributed generation (**SSDG**) on the voltage, load and transformer condition at a transformer level of low voltage (**LV**) networks is contributing to this issue.<br>We also note that the current buy-back rates offered by retailers incentivise self-consumption of electricity generated from SSDG systems and that this helps to reduce the impact of the issues outlined in the consultation paper. |
| Q3: Do you agree these options broadly represent the range of actions we could consider at this time? Are there other broad conceptual options we should consider that are not covered by these three approaches? | Yes. |
| Q4: Do you think the Authority should pursue the types of measures that Option B would | |

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| require? If not, please outline your alternative preferred approach, including if possible the costs and benefits. If you consider there is a valid Option C-style alternative, please provide details, including your view on how your alternative would meet the Authority's statutory objective. | We support Option B, with the caveat that only optional features should require an approval under Part 1. |
| Q5: Do you have any comments on the draft EEA guide's stated objectives? | Where 'Objective B' is to avoid disruption to electricity consumers and SSDG owners, it should, in our view, require the provision of effective guidelines for using solar and batteries during electricity outages. |
| Q6: What advanced power quality capabilities do inverters sold into the New Zealand market possess? | In our experience, most inverters are bought from Australian wholesalers and they have the advanced power quality functionality required in Australia under *AS/NZS 4777.2 (2015).*<br><br>However, as a lot of inverters still existed in the market when this standard was introduced in Australia, a lot of older inverter stock compliant with the *AS/NZS 4777.2 (2005)* was provided to the New Zealand market and this stock is still being installed locally. |
| Q7: Is it reasonable to assume that the advanced power quality modes outlined are currently available in the marketplace at no additional cost? If not, what are the likely incremental costs involved to obtain these modes? | Yes, in our view, most New Zealand distributed inverters compliant to *AS/NZS4777:2015* have the optional requirement of advanced power quality capabilities so would not incur additional capital cost.<br><br>We do however note the requirement to set volt-var and volt-watt settings to ensure they are suitable for local network requirements will increase installation times for equipment thus increasing install cost. |
| Q8: Would a default requirement to provide volt-var and volt-watt modes for all future inverter installations that use the Part 1A connection process have any unintended adverse consequences (for example, leaving a stock of unsold inverters that are otherwise compliant with the superseded AS4777:2005 standard suite)? Are these adverse consequences surmountable? | Genesis considers that adoption of inverters compliant with *AS/NZS477.2:2015* should occur as soon as possible, but, the proposed default requirement to provide volt-var and volt-watt (currently optional under the standard) could have unintended consequences for the limited availability of inverter equipment available in New Zealand that can go through Part 1A.<br><br>In our view, this default requirement is unnecessary and the impact on any businesses with stock of old inverters could be mitigated by communicating with the industry well in advance of any changes. |
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| Q9: What comments do you have about the hosting capacity assessment process described in detail in the draft EEA guide? | We disagree and believe investment in technology to monitor the effects of SSDG on the voltage, load and transformer condition at a transformer level of LV networks would clearly measure areas that are congested; please refer our response to Q2. It is our firm view that an SSDG site should not be supplying support to any network due to network under investment.<br><br>We also consider the application process, application form, and application processing fees should be standardised across the 29 networks. |
| Q10: Do you support the Code amendment request discussed in the draft EEA guide? If not, please explain why and, if possible, suggest an alternative approach. | No. We consider that an area that is identified as congested by active monitoring should go through Part 1. This would ensure long overdue investment is completed on the network. Any uncongested area could go through Part 1A with a *AS/NZS4777.2:2015* compliant inverter. |
| Q11: Do you think there is a problem or conflict with the '10 kW total' versus '5 kW per phase' thresholds respectively adopted in the Code and AS/NZS 4777.2:2015? If so, would you support aligning the Code threshold with the inverter standard? | Yes. We support a maximum of 10kW single phase or 5kW (21.7A) imbalance between phases on a multiphase property as per *AS/NZS4777.2:2015 C.8.5.*<br><br>We would prefer a simpler application process for larger systems (over 5kW). It also should be possible to use the simpler application process for SSDG systems that have limited their export to a set amount. |
| Q12: Do you think there are emerging problems with capacity or power quality from in-home electric vehicle chargers, or is it too early to tell? We are keen to hear industry views and experiences and from parties that supply electric vehicle charging equipment. | Yes. In our view there will be capacity issues that we should be planning for now. Demand response management system requirements should be incorporated in electric vehicle chargers coming into the New Zealand market. |

# Appendix D: Review of metering and related registry processes

| QUESTION | COMMENT |
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| **Issue #001 Electrical connection and disconnection of points of connection** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. |

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| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No, not with regards to ‘Problem 4’. In our view, the proposed solution creates more inefficiency than the issues itself presents, as explained below.<br><br>As a gaining trader, the sign up of a customer - where the discussion and action to reconnect occurs - can be quite separate from the (often automated) determination of whether an ICP switch is required and the processing of files if needed. As a losing trader, setting the switch date - and generating any AN/CS response files - is generally automated and triggered on the receipt of NT files.<br><br>To interrupt either of these processes will introduce significant operational inefficiency, which is ultimately borne by customers.<br><br>Timing will also be an issue as the confirmed (actual) reconnection date is not known until the return of field work completion details. This is likely to be after the AN response file is sent and quite possibly - given the current average switch time frame - after the CS file, which will require a switch withdrawal and re-submission; adding more effort, costs and delays. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | We do not agree to the amended changes to 10.33a in line, as per our response to Q2. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | The objectives, yes, but not the method, as explained in our response to Q2. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority’s statutory objective in section 15 of the Electricity Industry Act 2010. | In our view a better solution would be to amend the transfer switch notification (**NT(TR)**) file rules to allow a gaining trader to request a switch date that could be back dated (and, if within parameters, this would be the switch date). The date requested by the gaining trader would then align with the reconnection date and it would be dealt with under the existing switch frameworks.<br><br>This solution has the added advantage that it will create efficiencies for gaining traders in other areas e.g. alignment to contract start dates, dual product alignment. We note that a similar regime has been operating in the gas market without issue for some time now. |
| **Issue #002 Prohibition of net metering** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. |
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| Q2: Do you agree with the Authority's proposed solution? If not, why not? | Yes. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | No. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | Yes. |
| **Issue #003 Recovering of certification costs** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | In principle yes, but the Code needs refinement as per our response to Q3. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | The term 'assuming responsibility' in section 10.22 (2) is not a defined term and should be replaced with '*<u>MEP event date</u>*' or a similar term to remove any confusion between the acceptance of the MEP nomination, which can happen months prior to any intended taking over of the ICP, and the event date contained in the gaining MEPs first hit on registry.<br><br>Section 10.22 (4)(c) seems to overcompensate the losing MEP if the gaining MEP only uses the existing equipment for a short period of time i.e. if the gaining MEP does not replace metering equipment for a month after the MEP event date, it could be read that they need to compensate the losing MEP to the end of the current certification period, which could a number of years. We consider clearer wording is needed to specifically reference the pro-rata period is for the time the metering equipment is used. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that | Yes, provided the Code amendments recommended in our response to Q3 are accounted for. |

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| meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | |
| **Issue #006 Metering issue resolution timing** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No. We consider that given the MEP has the 'best endeavours' protection for circumstances outside their control e.g. in the event of customer-driven shut down, the timeframe to resolve the issue is excessive. Bearing in mind there is a customer and market settlement to occur at the end of all these issues, providing 5 weeks to resolve is a long time to have consumption uncertainty and inaccuracy. In our view, the time frame to resolve should be 10 working days. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | Genesis recommends section 10.46A (2)(b) is amended to read *"…<u>no later than 10 business days</u>..*" |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | Yes, provided the Code amendments recommended in our response to Q3 are accounted for. |
| **Issue #025 MEP updates of HHR, NHH and AMI flags** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | No. To Genesis it remains unclear why there appears to be a link between the ability of a meter to communicate remotely i.e. the determination of AMI and the resolution of data it is certified to record i.e. NHH or HHR.<br>In theory, it should be possible to have a NHH AMI that is only certified to NHH data level but transmits information to an MEP remotely; just as there could |

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| | be an HHR non-AMI that is certified to record at HHR intervals, but data needs to be downloaded remotely.<br><br>If the Code in its current form cannot provide for these distinctions, then it needs addressing, and is increasingly important with the growing diversity of traders and the products and services they offer to customers. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No. In addition to our comments above in response to Q1, while section 8 (12) of schedule 10.6 deals with noting the move from an AMI to non-AMI state, the only control over noting when it moves back to an AMI state once the issue is resolved is section 3(c) of schedule 11.4, which allows for 2 weeks. We suggest that 3(c) should also be 3 business days. Knowing promptly that an ICP is electricity connected or has resumed communicating is as important as the loss of communication. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | No. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | Yes, provided the Code amendments recommended in our response to Q3 are accounted for. |
| **Issue #026 Excluding non-market related meter registers** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. That said, it should be noted there are costs to traders if distributors pursue this course, even if non-market registers are not populated in the registry. This comes about from the configuration change of the meter that re-sets all registers on the meter, driving the need for a meter record and customer billing adjustment at the time of the change. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No. In our view, it is short-sighted to restrict the proposal to only non-market registers '…for the purpose of a distributor direct billing…'. As the provision of products and services continues to evolve, traders are likely to want bill customers on a register configuration that is different from the network pricing and market settlement. Currently |

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| | they are prevented for doing so as they would also need to populate the customer service register to the registry, which conflicts with network billing requirements. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | We recommend that proposed code (1A) should be re-drafted to remove the distributor direct billing restriction. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes, if issues mentioned above in response to Q1-3 are accounted for.<br><br>Removing the need for any non-market registers to be populated will eventually mean the simplification (and thus efficiency gains) of configurations populated on registry as it removes the need for derived pricing configurations to accommodate NHH traders. The alternative is a regulatory change being made to accommodate a single participant's preference. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010. | Yes, provided the Code amendments recommended in our response to Q3 are accounted for. |
| **Issue #027 Meter resealing by traders and distributors** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No. Genesis considers references to updating the profile code if a load control device is bridged are not relevant: If a load control device is bridged, it will not change whether the profile under which the ICP is settled in the reconciliation process. What has changed is that the register content that was controlled load (**CN**) is now effectively uncontrolled load (**UN**), which are registry fields maintained by the MEP. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | We believe that if inclusion of a specific registry update is even necessary – noting section 10 of schedule 11.1 is fairy explicit that any ICP information changes are advised - it should reference the correct impacted registry data fields and the participants responsible for updating those fields. |

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| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority’s statutory objective in section 15 of the Electricity Industry Act 2010. | Yes, provided the Code amendments recommended in our response to Q3 are accounted for. |
| **Issue #028 Meter bridging** | |
| Q1: Do you agree with the Authority's problem definition? If not, why not? | Yes, although there seems to be confusion as to how meter bridging arises.<br>The situations provided as examples are counter to the vast majority of cases, in which the trader is not aware bridging has occurred until the return of field work information (and often not even then). It is very rare that a trader will instruct an MEP or field service agent to bridge a meter. The request will be for a reconnection and the field contractor makes the call if bridging is required. We note that in almost all cases, issues surrounding bridged meters arise from the trader not being aware of it occurring. |
| Q2: Do you agree with the Authority's proposed solution? If not, why not? | No. The proposal seems overly complex for what could be a fairly simple process. |
| Q3: Do you have any comments on the Authority's proposed Code drafting? | Yes, as per our response to Q2 and Q5. |
| Q4: Do you agree with the objectives of the proposed amendment? If not, why not? | Yes. |
| Q5: Do you agree the proposed amendment is preferable to any other alternatives that meet the objectives of the proposed amendment? If not, please explain your preferred option in terms consistent with the Authority’s statutory objective in section 15 of the Electricity Industry Act 2010. | In our view the amendment should be changed so that the general process is as follows:<br>If a MEP or their agent - in carrying out a trader or distributor request to reconnect supply - is required, within the parameters defined in (3), to bridge a meter they must;<br>a) advise the requesting party of the reconnection (we note this may not be current trader if reconnection is as a result of a switch or distributor requested) and the current trader of doing so within 1 business day, |

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| | including an event read at the time of reconnection;<br>b) arrange for the unbridging at the earliest practical time; and<br>c) on completion of unbridging, advise the requesting party of the reconnection and the current trader of the date and time of the unbridging within 3 business days.<br><br>The responsible trader or the gaining trader (if a reconnection request followed a switch) must ensure estimated consumption during the period of bridging is determined when advised of a bridged meter. |