Appendix A
Submitter: Genesis Energy

Question	Comment
General Comments	
Q1; Which, if any, of the 29 issues raised in this paper do you consider should not be investigated further? Please give reasons.	All should be considered, though some of the proposed options should not be pursued. We have addressed these individually below.
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.	For multi ICP commercial and industrial customers having differing ICP switch processes between mass market and HH switch types based on the differing meter categories at each ICP for the same customer creates inefficiencies.
Q3: Do you consider the ICP switching processes set out in the Code, together with the amendments discussed in this paper, are likely to remain fit for purpose over the next 10 years? Please give reasons.	Only if viewed from the position that the current environment for services at an ICP will remain unchanged for the next 10 years. This is unlikely with the Authority already exploring the possibilities of multiple traders for multiple services at the ICP. Much of the current complexity associated with the Trader ICP switch process has come about as functionality associated with customers changing retailers has become incorporated with the ICP switch process due to steps in the ICP switch process being convenient triggers. If the industry does progress to a multiple service/trader world, then the ICP switch processes will have to be simplified back to recording change of services/providers at the ICP.
Q4: Should any alternative ICP switching processes be considered in the longer term? Please give reasons and outline an alternative	Along with a simplified ICP switch process, as discussed above, multiple services may require consideration of a greater differentiation of the metering asset owner obligations/costs from the metering data services provider obligations/costs.
Q5: Should the registry be modified to enable event maintenance to be conveyed via an API? Please give reasons	Yes, this could be provided as an alternative which may over time become the default mechanism.
Q11: Can you give an indication of cost and benefit?	In general, these changes would struggle to have positive return on cost if implemented individually, so it only makes sense if the changes of associated issues are implemented together e.g. changes effecting ICP switch logic, file construct and timings. For instance, issues number 1 – 5, 7, 9,11,12,14,15,19 & 23 all interact with NT or CS file processes of a trader ICP switch so could be considered in a grouped change. Under each issue we have tried to give an indication (from our perspective) of the *individual* cost of our preferred option from major (being changes to underlying core system logic or functionality) to minor being local configuration change or non-system process change. Beneficial results of the changes are on a similar significant to minimal range.
Q12: Which, if any, options for changing the ICP switching processes do you consider should be fast tracked? Please give reasons.	Issue numbers 1, 2, 4, Option 2 of Issue number 5, Options 1 & 6 of Issue number 10, 13, 14, 15, 16. These issues either present significant long-term benefit or are not overly onerous implementation to improve efficiency overall.

Q13: Which, if any, options for changing the ICP switching processes do you consider could be implemented using a combination of a fast-tracked option, followed by a more substantial change at a later time. Please give reasons	Nil

Issues with Trader ICP switching process

Issue #1 The actual trader ICP switch date is delayed or is not as agreed.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	The situation is driven by the current rules so potentially impacts on all switches.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 2 is the preferred alternative. Changing the code so the gaining trader sets the switch date in the NT file is simplest solution. There will be system change with either option, but Option 2 is the lessor, being only a logic change for setting the switch date, whereas option 1 requires system workflow, process, exception management and file creation changes. In the absence of a gaining trader provided switch date, the date the NT file is received by the Registry should become the default switch date.
Q9: Are there any advantages or disadvantages that are not included for each option?	Option 2 will bring electricity in line with the gas switch rules where this ability already exists. Option 2 has the added advantage that, when combined with changes discussed in Isuue#9, addresses the multi ICP 'C&I' customer inefficiencies
Q10: Are there any foreseen implementation issues?	There will need to be parameters set for the date requested to allow for the few exceptions where the requested date is unrealistic (essentially back dated into previous billing periods, or too far future dated. The gas rules allow for this and should be used as a template. The gas rules allow for these parameters to be exceeded if the losing trader agrees to meet customer requirements.
Q11: Can you give an indication of cost and benefit?	Costs are major, benefits are significant.

Issue #2 Replacing/modifying metering installations on the trader ICP switch event date is difficult	
Q6: Do you agree with the description of the issue? Please give reasons	On the whole yes, but it should be noted that the metering requirements imposed by distributor UoSAs restricting competition is not a switching issue, and the statement that "most trader ICP switches are backdated" is only true insofar as it relates to move in switches. There may be some confusion between a back dated event date as at the NT/AN time as opposed and that the event date has to pass before the CS file containing a read for that date is sent.
Q7: How material is this issue?	Our experience is that the occurrence of meter change at switch time is infrequent. Most commonly it occurs with change for post pay to pre-pay metering and that change does not seem to cause issues (possibly because of the close association between gaining retailer and pre-pay metering supplier).
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	On the occasional situation where a switch event needs to align with a meter change a move in switch type with a gaining retailer determined event date is used to effect the change. As such Option 1 is by far the best solution as it mirrors the current operational solution.

Q9: Are there any advantages or disadvantages that are not included for each option?	These are the same as for Option 2 for Issue number 1 (being essentially the same solution).
Q10: Are there any foreseen implementation issues?	These are the same as for Option 2 for Issue number 1 (being essentially the same solution). Adopting option 1 (within parameters), then the impact of Shortcoming 7 (a need to change switch date) is minimised as there will be an expectation that the gaining will understand the ICP sufficiently prior to sending the NT thus removing the first cause. For the few times the second cause comes into play the existing operational process (withdrawal for Date Failure and re-submit new NT with new date) would continue.
Q11: Can you give an indication of cost and benefit?	Costs are major, benefits are significant

Issue #3 Gaining traders face difficulties ensuring accurate switch event meter reads for category 1,2,& 9.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	The shortcomings highlighted have arisen as the availability of more accurate and timely meter data has increased while the Code still talks to a model of less frequent and less refined meter data. This has the potential to impact to greater or lesser degree all switches and a fundamental change to the provision of switch event data is then required to address this.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	To correctly address the shortcomings only, Option 3 (with modifications noted below) in conjunction with Option 5 resolve all issues.
Q9: Are there any advantages or disadvantages that are not included for each option?	The greatest disadvantage to Option 3 is the implementation costs required by participants (retailers and MEPs). However, this is not to be unexpected with such a fundamental change as required here. Much of this cost will be offset by the long run benefit of the reduction in processing of RR read revision process. Having a trader produce a CS file for every switch for use in the exceptions when a MEP cannot produce read data is operationally inefficient. An alternative is noted below.
Q10: Are there any foreseen implementation issues?	Under Option 3, with MEPs supplying the switch event reads, there is no other data contained in the CS file that is not already contained in the Registry so calls into doubt why a CS file needs to be produced by the losing trader at all. As there will be major change to accommodate for the 'return CS file' with the MEP switch event reads, then the losing trader making the additional change not to produce a CS file, will carry only marginal cost. When combined with the Gaining trader setting switch date, a MEP/Registry created CS file sent to both traders then represents large gain in ICP switch efficiency. This amended process will of course only be applicable to ICPs with communicating AMI metering. Whether a switch requires the losing trader or the MEP to produce a CS file could identified to all parties by a repurposed AN file, produced by the Registry, and triggered on the receipt of the NT.
Q11: Can you give an indication of cost and benefit?	Costs are major, benefits are significant.

Issue #4 Delay in receiving first AMI read after switch	
Q6: Do you agree with the description of the issue? Please give reasons	Yes

Q7: How material is this issue?	Is only material for Traders who have billing model of less than 10 working days. The circumstance raised in the shortcoming around market and network settlements (4.88 (c)) is not result of the delay per se, but of the Traders not using the data when received to amend their estimates.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	The presented option (with modification noted below) will address issue.
Q9: Are there any advantages or disadvantages that are not included for each option?	No
Q10: Are there any foreseen implementation issues?	The staggered attainment rate adds complexity that is not required. The change should simply be a reduction of the current 10 business days to 3 business days. This would align with many other similar obligations in the Code. The obligation should be stated in business days for consistency and to account for weekends when many traders will not process files received. When combined with the MEPs supplying the switch event read data (the start read of a gaining trader's first billing period), provision of ongoing daily read within 3 b/days should ensure an accurate first bill experience for the customer.
Q11: Can you give an indication of cost and benefit?	Minor cost with moderate benefit.

Issue #5 AMI switch reads nor necessarily midnight meter readings	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Not material for us as issue raised have been addressed with commercial KPIs with MEPs.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	The combination of Option 1 (subject to comments in Issue #3) combined with Option 2 resolve all shortcomings.
Q9: Are there any advantages or disadvantages that are not included for each option?	Only those already addressed in issue number 3.
Q10: Are there any foreseen implementation issues?	Only those already addressed in issue number 3.
Q11: Can you give an indication of cost and benefit?	Minor cost with moderate benefit.

Issue #6 Interpreting ICP switch as consumer switch	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	This issue immaterial.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 is preferable as although it will come with the bigger implementation cost, the ongoing operational cost is less.
Q9: Are there any advantages or disadvantages that are not included for each option?	The solution will not identify all changing customers, only those where a customer changing retailer triggers the need for ICP ownership change.
Q10: Are there any foreseen implementation issues?	

Q11: Can you give an indication of cost and benefit?	Option 1 should only be implemented as part of other switch process / NT file logic changes (e.g. Issue #1 Option 2) as the changes required to include additional data in the existing NT file are extensive and benefit does not warrant the spend on a standalone basis. The benefit is minimal.

Issue #7 Identifying mass customer ICP switches	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	This issue is immaterial.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 and 2 presented should be disregarded as the costs required to alter system logic, file creation and processing far exceeds the impact of the shortcoming. Option 3 is the preferred option. For the number of times this situation occurs, combined with the fact that a mass transfer of ICPs is generally involves manual operations by the two traders involved to ensure correct transfer dates etc, the creation of a distinct switch type is the most efficient solution.
Q9: Are there any advantages or disadvantages that are not included for each option?	Option 3 ensures costs are only borne by those involved on the occurrence of a mass transfer, rather than on the whole industry as imposed by Options 1 & 2. Option 3 may present some advantage for the traders involved as it will enable them to also distinguish in their internal reporting of customers changed through the mass transfer and BAU churn occurring at the same time.
Q10: Are there any foreseen implementation issues?	No
Q11: Can you give an indication of cost and benefit?	Minor costs with minimal benefit

Issue #8 Rules for acknowledging trader ICP switch request notifications	
Q6: Do you agree with the description of the issue? Please give reasons	No. Before making changes to the contents or the construct of the AN file, it should first be determined whether, because of the other changes to the ICP switch process that may occur, the AN file is needed. Then the content should be determined to suit any value-added purpose the file serves after the changes.
Q7: How material is this issue?	From our perspective the issue is immaterial, but we do not have concrete evidence of the extent of the continued use of the AN files received by other traders.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	None of the options are preferable as they are talking to current state, and not what the likely needs after the other ICP switch process changes. Should the AN file be determined to have a value then we suggest that a new set of content codes will be required (including combination codes). These codes however should be limited to data that is not already recorded in the Registry *and* provides concrete data *and* the information is needed by gaining traders to complete the ICP switch. For example, although the losing trader may have their customer contractor, so would be required to include CO code, there is no way of knowing whether it is the same customer the gaining trader has, hence the use of the Code carries doubt. And in the cases that a customer is breaking an existing contract to change traders, that is an issue between the customer and the losing trader to resolve (payment of penalty, customer changes mind on switch etc).

Q9: Are there any advantages or disadvantages that are not included for each option?	As the usefulness and purpose of the AN file has not been tested with the industry considering other ICP switch process changes, there is a risk that the options proposed will exchange current shortcomings for a different set of shortcomings.
Q10: Are there any foreseen implementation issues?	Depending on the final definition of use of codes, traders may not have data in such a way as to be able to be included systematically with AN files e.g. the revised meaning of AD code proposed in Option 1 (which now has no association with AMI), the losing trader will not necessarily know that the meter is in the process of being installed, and even if they are aware a install is planned for the ICP, the final details (completion date etc) are not known until the return of the meter change data by the MEP, so the traders system may not have any data to trigger inclusion of the code.
Q11: Can you give an indication of cost and benefit?	Moderate costs with benefits dependent on final position of AN. As present, minimal benefits.

Issue #9 Different timeframes for different types of ICP switches add complexity	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	For mature traders who have grown with the evolution of the ICP switch process this is not an issue, however, it may be seen as an issue if a new entrant is not familiar with their obligations.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	The single option proposed does not remove the root cause which is there different switch processes depending on the reason for the trigger of the need for the ICP switch, rather than the efficient functionality of the ICP switch process itself. An alternative option is that, in conjunction with changes to allow the gaining trader to set the switch event date, the switch type and the provider of the CS file (gainer or loser) are simply information fields within the NT file. From that point only a single process is required to complete ICP switch.
Q9: Are there any advantages or disadvantages that are not included for each option?	The alternative option has the added advantage that it addresses the multi ICP ‘C&I’ customer inefficiencies.
Q10: Are there any foreseen implementation issues?	Implementation costs of the alternative option mean it would only be viable to implement in conjunction with other changes to the ICP switch process.
Q11: Can you give an indication of cost and benefit?	Moderate costs and benefits.

Issue #10 ICP Switch withdrawal inefficiencies.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes, although it is unclear whether the withdrawal numbers quoted in the paper are inclusive of CR/CX (win back, customer error) withdrawal codes and whether the increase is due to greater win back activity. The only increase in other withdrawal types we have noticed in recent times is the requirement for WP withdrawals as a result of historical instances of cross metering/ICP error needing to be corrected.
Q7: How material is this issue?	This varies for each of the shortcomings. Shortcomings 1, and 5 are worth pursuing, Shortcoming 3 partially so, and Shortcomings 2 and 4 are non-issues.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	*Option 1 addressing shortcoming 1:* Agree that this addresses issue, though ‘switch completion’ will need to be defined – suggest it is the date CS file is received by the Registry.

	Option 2 addressing shortcoming 1: We disagree that this change is required. Any withdrawal after the 2-month window creates significant customer billing issues. Other than the issue created by back dated switches (addressed by Option 1) it is rare to have customer related issues after two months and if they do take that long to manifest it is likely to be down to the trader's internal processes not regulatory failure. There are occasional ICP issues that manifest themselves after some time and where necessary traders work with each other to process any withdrawals / re-switch required to correct situation. *Option 3 addressing Shortcoming 2:* This should not be progressed. When interactions are required between traders it is generally because the situation is out of the ordinary and merely changing the mechanism of the interactions will not address the issues of parties not responding, and with the change proposed, will significantly increase the ongoing operational cost. *Option 4 addressing Shortcoming 3*: We are not sure there is an issue here. The functional specification the reasons seem clear enough, so we are unclear why that is presented as the reason for traders using incorrect withdrawal reason codes. If definitions are to be clarified, it should not be done in isolation and feedback on any change in wording should be widely sought to ensure intent of withdrawal codes are not altered inadvertently. *Option 5 addressing Shortcoming 4*: Strongly disagree that this change should be implemented as presented with a carte blanche requirement to accept any withdrawal. There is an argument that CR/CX withdrawals should have mandatory acceptance (on the condition that the receiving trader of the NW believes the correct withdrawal code is being used). But for all other withdrawal types the receiving trader needs to have the ability to investigate the request and decline if they find that reasoning for the withdrawal is non-existent. This is required to prevent the use of the withdrawal process to reverse a regretted business decision or mitigate poor internal trader processes rather than for genuine issues at the ICP. *Option 6 addressing Shortcoming 5:* Agree this would be a useful enhancement.
Q9: Are there any advantages or disadvantages that are not included for each option?	As above
Q10: Are there any foreseen implementation issues?	Not for the Option we agree should be pursued.
Q11: Can you give an indication of cost and benefit?	Options 1 and 6 – Minor costs with minimal benefits.

Issue #11 Different meter reading timeframes.	
Q6: Do you agree with the description of the issue? Please give reasons	No. It seems two distinct issues may have been conflated. i) Meter replacements cannot be reflected accurately on the Registry (a replacement at the time of an ICP switch compounds the problem, but the ICP switch is not the root cause), and ii) confusion on the date of the read to supply as the switch event date.
Q7: How material is this issue?	Part i) is material and has impacts exceeding the ICP switch process (e.g. see Issue #22). Part ii) is becoming less of a concern as more traders understand the requirements.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	The option does not address the underlying causes of the issues.

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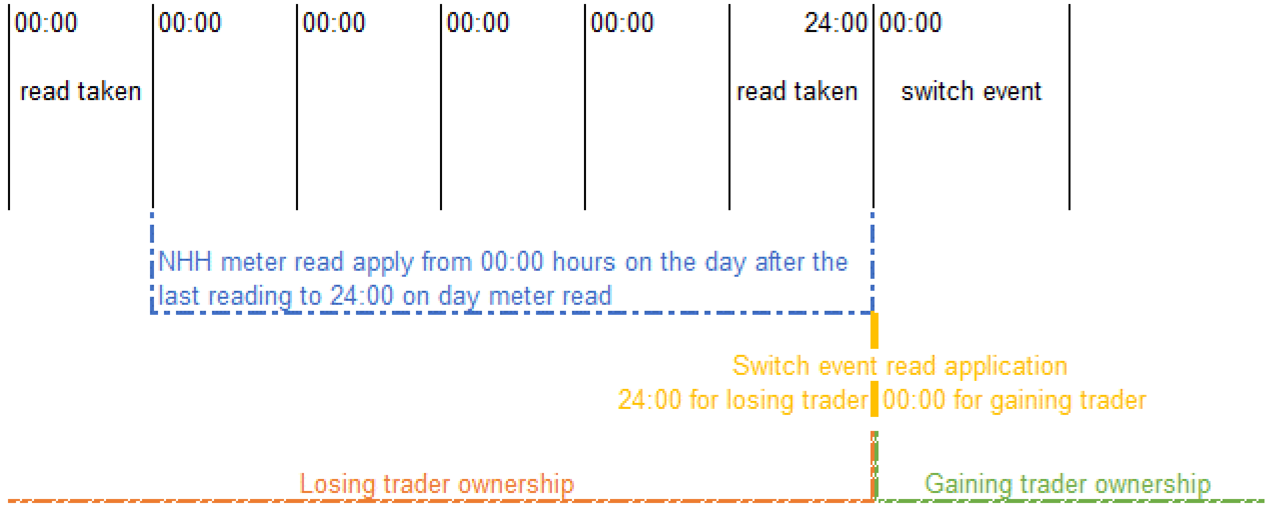
<td>Part i) is created by the current Registry functionality not allowing for two metering events on the same day. This can be resolved by changing the Registry functionality to allow events to be logged by date/time rather than date alone. i.e. in this way the meter removal event and the new meter event and retailer change event (switch event) can be recorded on the same day if that is what has occurred.

Part ii) arises not because of the wording of the Code (which effects the correct switch read for the boundary between the losing and gaining traders – see diagram below), but by a trader either supplying or asking for a read taken on the day of the switch event rather than the day before. This behaviour, if allowed has the effect of pushing the boundary read between the losing/gaining trader out by 24 hours.



For the change proposed to give rise to the correct boundary read, it would require traders who are currently compliant with the Code to make significant changes to their systems to now obtain reads on the switch event day (technically outside their ownership period so could cause issues with MEP data supply agreements) simply to align with non-compliant traders.</td>
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<td>Q9: Are there any advantages or disadvantages that are not included for each option?</td>
<td>As above.</td>
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<td>Q10: Are there any foreseen implementation issues?</td>
<td>As above.</td>
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<td>Q11: Can you give an indication of cost and benefit?</td>
<td>Moderate costs and significant benefit (wider than this issue) for Part i).
Significant cost with no benefit for the proposed solution to Part ii).</td>
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Issue #12 Switch event meter readings cannot be obtained despite best endeavours	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Only exceptional occurrence, but only resolution is to breach code when occurs.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Both options should be implemented, i.e. allow estimates where actual or permanent estimate is not available and create guidelines on what constitute reasonable endeavours to obtain.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor cost for minimal benefit.

Issue #13 Registry functionality prevents retailer event updates during a switch	
Q6: Do you agree with the description of the issue? Please give reasons	Yes, but it only partially describes the situations where the functionality causes issues. No Retailer fields such as proposed MEP, or unmetered load details can be updated during a switch.
Q7: How material is this issue?	Less so now that switch times have reduced.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Neither of the options presented addresses the underlying cause so present no overall benefit. Option 1 reduces operational efficiency by introducing a band-aid exception process, and Option 2 only addresses a single symptom. Also, due to file timings, the situation of the AN file be sent prior to status change is likely to be the norm. Suggest that the resolution for this issue is to remove the block on Retailer field updates while switch is in progress.
Q9: Are there any advantages or disadvantages that are not included for each option?	Neither option addresses actual cause nor whole of issue.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Options presented – Major costs Our proposed alternative – Minor costs. Correction of the issue will have moderate benefit.

Issue #14 Switch Event meter readings for category 3 – 5 metering installations	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Of minor materiality.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 will address the issue. In addition, we suggest the label of the 'settlement indicator' field also be changed is it clear now that this filed has no relationship to whether the channel date is used to settle market or not.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.

Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor cost with moderate benefit.

Issue #15 Replacement Read process is inefficient	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Varies across the shortcomings
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	*Option 1(a) addressing shortcoming 8 and 3:* Agree with this change *Option 1(b) addressing shortcoming 8:* Disagree with this change. This option will create significant extra effort for an issue that has a very low occurrence. The onus is on both traders to ensure all reasonable efforts are made to ensure the switch read is correct at the first replacement discussions. *Option 2 addressing shortcoming 2:* Agree with caveat that the +/- 1KWh threshold is applied per channel. *Option 3 addressing shortcoming 1 & 7*: Mandated use of midnight reads where the ICP has AMI metering will improve the efficiency of the RR process generally as it will reduce the overall number of RRs required. The biggest disadvantage of this option is that it will require traders who do not currently have a need to obtain midnight reads to enter into commercial contracts with the MEP at the ICP for this single purpose. *Option 4 addressing shortcoming 4, 5 and 7:* Agree with the general principle of supplying MEPs with earlier notice of the switch and setting a deadline for them to commence supply of data to the gaining trader. But as with Issue number 4 option 1, a tiered compliance is unnecessary, adds complexity and is proposed to address a situation that is a non-issue. If a meter is not communicating, then it is by definition, not and AMI and the standard NHH switch read determination will apply. Any exceptions outside of the mandated timeframes for commencing data supply could be handled with a 'reasonable endeavours' criteria as with other areas of the Code. As with Issue #4 timeframe to commence data supply should be 3 Business Days. *Option 5 addressing shortcoming 7 and 4*: Disagree as this option does not address either of the shortcomings stated. Shortcoming 7 can be addressed simply by changing the materiality threshold to be 200kWh per ICP rather than channel which is closer to the original intent. Shortcoming 4 can be addressed, in conjunction with Option 4, extending the time allowed by the gaining HHR trader to request a NHH to HHR switch read adjustment from 5 business days to 10 business days. *Option 6 addressing shortcoming 6:* Disagree as the proposal will not affect any change as the trader will still need to follow up non-response irrespective of whether there is a codified timeframe or not. *Option 7 addressing shortcoming 6:* We agree a less onerous disputes process purely for the process where traders cannot agree a switch read would be useful.

	Option 8 addressing shortcomings 1,4 and 5: We disagree. The introduction of an extended timeframe is likely to introduce unintended complications to RR changes not impacted but the shortcomings. A simpler, more effective option would be to change the commencement of the 4-month counter from the switch effective date to the date the CS file is received by Registry. This has the added advantage of creating simplified management of RR timeframe as all switches will have same commencement date.
Q9: Are there any advantages or disadvantages that are not included for each option?	As above.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Options 1(a), 2, 4, 7 – Minor cost Option 3 – Moderate cost Our alternatives to Options 5 and 8 – Minor costs All changes would have moderate benefit.

Issue #16 Delays updating the registry may delay meter installation / connection	
Q6: Do you agree with the description of the issue? Please give reasons	No, distributor behaviour has moved on since this issue was first raised some time ago. There is now very little delay in the advancement of the ICP lifecycle from Request to New to Ready. The only issue we now have is ensuring that MEP systems are efficient enough that they look to load the metering details to the Registry at the same time as sending meter install paperwork to the trader, thus creating a timing issue as at that point the ICP status would move from Ready to Active/Inactive.
Q7: How material is this issue?	This is becoming more of an issue as the industry as whole becomes more efficient.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Whilst the option provided could affect the result required (meter details loaded as soon as fieldwork completed) it creates new issues in that it removes the trigger for traders to request meter hang (currently the move to Ready status) and comes at the cost of an additional step for traders to manage. An alternative solution would be simply to allow metering events to be entered against the ICP record at Ready status.
Q9: Are there any advantages or disadvantages that are not included for each option?	The advantage of the alternative solution is that with only a Registry functionality change and no other participant processes change, an efficiency gain can be made.
Q10: Are there any foreseen implementation issues?	Option 1 will create other issues as mentioned.
Q11: Can you give an indication of cost and benefit?	Option proposed – Major cost for moderate benefit. Our proposed alternative – Minor costs for moderate benefit.

Issue #17 Gaining trader connecting ICP before switch completes.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.

Q7: How material is this issue?	Connecting before the switch is completed is a common occurrence as it is done to provide a positive customer experience. Encountering difficulties if a switch is withdrawn is less common, but causes the issues identified.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Agree with the general principle of ensuring costs correctly align with ICP ownership. Enforcement of alignment of the connection date and the switch date can be achieved easily with the changes to the NT file to have the gaining trader set the switch date (see Option 2 Issue number 1). If the ICP is connected in error and the ICP needs to return to the original trader, then the losing (original) trader determines that either; the switch is *withdrawn*, and as such the costs associated with the switch period return to the losing trader, or the ICP is *switched back* with a new switch event date so that the costs associated with the switch period stay with gaining trader. In this way we avoid the inevitable inefficient money-go-round of traders having to calculate, invoice and pay short period costs with each other. In either case the losing trader has the decision as to whether the ICP is disconnected again by the gaining trader before the return or not.
Q9: Are there any advantages or disadvantages that are not included for each option?	Option proposed would create inefficient financial interactions between traders.
Q10: Are there any foreseen implementation issues?	Does not take much imagination to foresee arguments around the costs if they were to be invoiced as each participant will have different cost drivers.
Q11: Can you give an indication of cost and benefit?	Minor costs with moderate benefit if adapted as suggested to avoid invoicing between traders. The option as presented would have moderate costs with minor long-term benefits (reduced due to ongoing invoicing regime required).

Issue #18 A switch withdrawal can cause two ICP switches to be withdrawn	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Would be a rare occurrence, but frustrating when it occurs.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Support Option 1.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs with minimal benefit.

Issue #19 Average daily consumption not consistently calculated.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.

Q7: How material is this issue?	Minor.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 seems to not only codify the calculation of the daily average (a positive change) but change the obligation from providing a daily average at a meter installation level to be at a register level. Option 2, by making the provision of the average consumption optional, will eventually mean that daily averages will cease to be of any value. A gaining trader will not be able to build systems and expectations to use daily averages for estimations and checks if they cannot be sure of receiving the data in every switch. A third option could be to leave daily average as mandatory and at meter installation level as it is currently but specify in the functional specification a standardised methodology such as in (b) (i) & (ii) of Option 1. We would suggest however the minimum time period should be 14 days as many NHH read periods are less than 30 days apart and if a trader is receiving interval consumptions or daily reads two weeks is sufficient to determine an ICPs daily average consumption. Note: With the RR process, 7 days between reads is deemed sufficient to determine a daily average to back calculate a new switch event reading.
Q9: Are there any advantages or disadvantages that are not included for each option?	Option 1 introduces significant change cost, and Option 2 undermines usefulness of daily average data.
Q10: Are there any foreseen implementation issues?	None other than already mentioned.
Q11: Can you give an indication of cost and benefit?	Moderate costs if changed to be at register level, minor otherwise for minimal benefit.

Issues with Distributor ICP switch process

Issue #20 Distributor ICP switch process is manual	
Q6: Do you agree with the description of the issue? Please give reasons	Yes
Q7: How material is this issue?	For us this is only a minor issue.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	We agree with the proposal but propose one modification. It seems now that a trader will need to send a response for each ICP they trade on within the moving network (currently only need approve in general for all ICPs they trader on). As no response after 14 days is deemed to be an acceptance, we suggest codifying that response is only required if trader rejects the distributor switch i.e. default is acceptance unless stated otherwise.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs with minimal benefit.

Issue #21 Network Extensions not visible in Registry	
Q6: Do you agree with the description of the issue? Please give reasons	Agree with the description but disagree that this is an issue that needs addressing.
Q7: How material is this issue?	Immaterial.

Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	We disagree with the use of a new Reconciliation type code. This will create significant change to trader reconciliation, network billing, trading notifications and the Reconciliation Manager allocation systems to accommodate the new code. As pointed out in the paper both the parent network owner and the network extension owner need to be aware of new connections and outages and we are not sure how identifying the ICPs on the network extension (as pointed out should be known by both parties) is going to improve the (essentially commercial) working relationship between the parent and extension owners. If there is value in identifying ICPs with network extensions to better understand the makeup of the industry, then method of identification that does not impose such extensive change on the industry should be found.
Q9: Are there any advantages or disadvantages that are not included for each option?	Significant change costs to many industry systems to accommodate.
Q10: Are there any foreseen implementation issues?	As above.
Q11: Can you give an indication of cost and benefit?	As presented, major costs for almost no benefit.

Issue #22 ICP status change part-way through day	
Q6: Do you agree with the description of the issue? Please give reasons	Rather than an issue of its own, the shortcomings described are further symptoms of one of the underlying causes of Issue number 11.
Q7: How material is this issue?	We do not experience any issues currently but is likely to be a growing concern as the industry becomes more half-hour by default.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Both options will address the concerns expressed in the paper, but do not present a long-term solution which would require time-based event logging within the Registry.
Q9: Are there any advantages or disadvantages that are not included for each option?	The changes required by traders (and MEPs) are not insignificant with impacts on reconciliation, field services and billing /registry interfaces effected.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Major costs, but along with associated issues above significant benefit.

Issues with MEP ICP switching process

Issue #23 Provision of initial metering data not always timely	
Q6: Do you agree with the description of the issue? Please give reasons	These are shortcomings are restating of the same concerns raised in Issue number 4 and Issue number 15.
Q7: How material is this issue?	Becoming more so as industry is becoming more responsive to customers.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	*Option 1 addressing shortcoming 2:* Agree with this proposal but question the need for AN files to also be delivered, particularly in the light of proposed changes to NT file. *Option 2 addressing shortcoming 1 & 3:* Part (a) of the option is a repeat of Option 1. See our comments on Issue #4, and Option 4 of Issue #15 as the tiered compliance of part (b) has the same problems. A single compliance timeframe of providing access within 3 business days should be pursued.

	Option 3 addressing shortcoming 1,3 and 4: Shortcomings 1 and 4 are addressed by option 1 and the extension of NHH to HHR gain read alterations to 10 business days (see option 5 issue number 15). Shortcoming 3 is a commercial issue not solved by regulatory intervention as it has implications to the data services agreements held by both the gaining and losing traders. *Option 4 addressing shortcoming 5:* This shortcoming is a commercial issue between the trader and its meter data service providers for the trader to meet its regulatory obligations (there are implications on the overall cost of data delivery that the trader may or may not wish to incur), so as such a regulatory intervention should not be pursued.
Q9: Are there any advantages or disadvantages that are not included for each option?	The staggered attainment rate adds complexity that is not required. The change should simply be a reduction of the current 10 business days to comply to 3 business days. This aligns with many other similar obligations on participants in the Code. The obligation should be stated in business days again for consistency and to account for weekends when many traders will not process files received in any case.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs with moderate benefits.

Issue #24 No standardised meter reading file formats.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes, though we feel the issue is more around the minimum data content that should be supplied rather formatting details such as the order of data or file type.
Q7: How material is this issue?	We do not see this as a major issue. While the format differs from MEP to MEP based on their data collection systems, the content of the files is now generally the same. Where we have experienced difficulties in the past is not the file formats, but the inability of MEPs to deliver the required content.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 should not be pursued as it would likely result in all existing data supply formats needing to be altered to align with standard (as a single standard cannot match all existing formats), resulting in costs that the issue could not justify for resolution. Option 2 of a default format that is available only if MEP and traders do not agree an alternative is viable, though a check that the additional overall cost of all MEPs enabling and maintaining the ability to provide the default version does not come with a greater cost to all participants than the cost to individual traders.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	None if a default approached is adopted.
Q11: Can you give an indication of cost and benefit?	Moderate if mandatory standard imposed, Minor if used as a default. Benefits of change would be minimal.

Issue #25 Gaining and losing MEPs cannot use same MEP event date	
Q6: Do you agree with the description of the issue? Please give reasons	Yes, though this issue is not restricted to situations that involve a change of MEP. It also occurs with meter changes and many other participant events. (e.g. see Issue number 11)

Q7: How material is this issue?	This is becoming a fundamental shortcoming of Registry functionality as the industry matures to make greater use of intra-day data differentiation
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Option 1 is the solution to the underlying problem of the Registry functionality. It does present a significant change to the current functionality. Option 2 does not actually address the issue but simply shifts the days effected, the Registry records will still be inaccurate in showing that the removal and addition of metering occurring on different days and al the associated issues with that remain.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Option 1 has moderate costs but along with associated issues above, significant benefit. Option 2 has no benefit.

Issue #26 Registry Metering records do not differentiate between metering types	
Q6: Do you agree with the description of the issue? Please give reasons	No. For shortcoming 1, the first portion set out in paragraph 6.61, the Registry records already differentiate between the metering types listed (other than the new lower levels of detail for C&I metering not previously deemed necessary for recording) – just not with a single field. The paper correctly notes that the determination can be made by reading multiple fields, but the 'result' is not reported as a single data field. Thus, the issue is simply the result of Registry business rule determinations that are currently not reportable. The second part of shortcoming 1 (paragraph 6.62) is restated as shortcoming 2.
Q7: How material is this issue?	Issues is moderately material, with shortcoming 2 being more of an issue for industry participation and innovation than shortcoming 1.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	While is it always risky re-purposing existing fields in datasets, and it is generally preferable to introduce new data via new fields, Option 1, with modifications, can address both issues. Use of Y, L and C present no real issues as these determinations can be made already from the existing regime. Along with N and I we propose the addition of S for 'Stopped'. Use of these codes are more complex, not so much in their intended use but when the transition between them and Y occurs. We suggest S is used when a previously communication meter fails communication attempts for more than 7 consecutive days. This would trigger the MEP/Trader non-comms process, and if communication is not reinstated the flag changes to N. I is used when a communicating meter misses 2 separate periods of 3 consecutive days of failed communication attempts within a 14-day period. The ICP would return to Y if in a period of 30 days there were no periods of greater than 2 days of failed communications. N is used when either communication does not commission at the installation of the metering, or if communication subsequently stops and the non-communication issues cannot be resolved after application of the MEP/Trader non-comms process.

<table>
<tr><td></td><td>In this way we would see the Y, S, I and N codes would interact as follows and would provide a clear indication of the current state of the AMI metering.
<table>
<tr><th>Scenario</th><th>Code</th></tr>
<tr><td>Meter install comms successfully commissioned</td><td>AMI = Y</td></tr>
<tr><td>Meter install comms not commissioned</td><td>AMI = N</td></tr>
<tr><td>Previous AMI = Y fails communication 3 consecutive days twice in 14 days</td><td>AMI = I</td></tr>
<tr><td>Previous AMI = Y fails communication 7 consecutive days, MEP/Trader non-comms process triggered</td><td>AMI = S</td></tr>
<tr><td>AMI = S, communication restored</td><td>AMI = Y</td></tr>
<tr><td>AMI = S, communication unable to be restored</td><td>AMI = N</td></tr>
<tr><td>AMI = I fails communication 7 consecutive days, MEP/Trader non-comms process triggered</td><td>AMI = S</td></tr>
</table>

We do not support the extension of the AMI field to include numeric characters to indicate how intermittently the meter communicates, as we do not believe a number could be determined for the majority of ICPs with enough confidence to be of any use.
These new codes would be returned in Registry reporting via the existing AMI field reporting and the current GUI only field indication non-communication can be removed as would now be surplus.</td></tr>
<tr><td>Q9: Are there any advantages or disadvantages that are not included for each option?</td><td>In addition to addressing the issue, the codes suggested above may assist MEPs and Traders in managing non-communication meters.</td></tr>
<tr><td>Q10: Are there any foreseen implementation issues?</td><td>As well changes to MEP systems, any changes to the AMI flagging will have impact on traders systems and possibly other participants in terms of ICP reporting.</td></tr>
<tr><td>Q11: Can you give an indication of cost and benefit?</td><td>Moderate costs but significant benefit.</td></tr>
</table>

Issue #27 MEPs not updating the Registry to record removal of metering	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Unknown.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	We favour option 1 as this addresses the break point in the process and does not create additional work for innocent parties in the case of an error. In addition, we wonder if allowing a distributor to decommission an ICP which still maintains a metering record may create the potential for the distributor to breach the code (which requires electrical installations to be removed before decommissioning) if meter is still in place.
Q9: Are there any advantages or disadvantages that are not included for each option?	Option 2 may create additional work for traders as well as MEPs if ICP if distributor decommissions an ICP in error if the trader uses metering event to update their system.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs for minimal benefit.

Issue #28 Time given for MEPs to update Registry	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	More material in an environment where industry is reacting faster all the time.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	The proposed option will achieve the aims.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs for moderate benefit.

Issue #29 MEP nomination not being sent to Registry prior to physical change occurring.	
Q6: Do you agree with the description of the issue? Please give reasons	Yes.
Q7: How material is this issue?	Was an issue in the past, but as traders and MEPs have gained a greater understanding of of the implications of nominating a MEP late it has dropped away to be an uncommon exception now.
Q8: Where there are multiple options, rank your preference for the options starting at 1 for preferred	Because of the various ways a MEP/meter change can be initiated (customer request via contact centre, MEP certification programme, trader driven deployment, meter sales etc) a more effective control would be to codify that a MEP cannot commence physical work until it is confirmed they have been nominated as MEP.
Q9: Are there any advantages or disadvantages that are not included for each option?	No.
Q10: Are there any foreseen implementation issues?	No.
Q11: Can you give an indication of cost and benefit?	Minor costs for minimal benefit.