



**Response to the Electricity Commission's  
consultation on Parts E to J of the Rules**

From

**Contact Energy Limited**

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## Introduction

Contact Energy welcomes the opportunity to respond to the Electricity Commission's consultation paper. Contact's response follows over the page.

For any questions related to this submission, please contact:

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## Submission

Paragraph or rule no.	Comments
Chargeable Capacity definition, Part A	Contact believes that the definition of Chargeable Capacity requires updating to achieve its original objective of supporting the identification of the fixed line charges applicable to an ICP. Contact recommends that this definition should be amended to be: "means only the capacity value that the <b>distributor</b> applies as part of the fixed line charge calculation, but which might not be the actual installed capacity at the relevant <b>ICP</b> "
Distributor Installation Details definition, Part A	Contact believes that the definition of Distributor Installation Details requires updating to achieve its original objective of supporting the identification of the fixed line charges applicable to an ICP. Contact recommends that this definition should be amended to be: " means only that information, additional to <b>price category</b> and <b>chargeable capacity</b> (where applicable), that is required to unambiguously define the fixed line charges applicable to an <b>ICP</b> ".
Price Category definition, Part A	<p>Contact believes that the definition of Price category requires updating to achieve its original object of being a single code to uniquely identify the fixed line charges to an ICP. Contact recommends that this definition should be amended to be "means a single code in the schedule <b>published</b> by any <b>distributor</b> that is used to unambiguously define the line fixed charges, and (where applicable) the related set of possible variable charges, applicable to an <b>ICP</b>"</p> <p>In addition Contact believes the Registry should be modified to validate the application of a single code.</p>
Rule 10.1.1 of Part E	Contact questions whether the 6 month timeframe to complete a Distributor audit is appropriate given that Reconciliation Participants have only 3 months for the same requirement. Contact believes the timeframes for both Distributor and Reconciliation Participant Audits need to be consistent.
Rule 10B.1 of Part E	<p>Contact believes this rule cannot be complied with as the Commission has not published the prescribed form of an audit report. While the Commission has published audit guidelines identifying what must be audited it has not for the audit report format.</p> <p>Contact recommends that this proposed new rule not be implemented as a Distributor should not be responsible for the performance of a Commission approved Auditor.</p>

<p>Rule 13 of Part E</p>	<p>While this rule requires the type and capacity of unmetered load to be identified and provided to the Distributor, additional information needs to be provided to (or determined by) the Distributor to ensure this unmetered load is correctly accounted for, namely:</p> <ul style="list-style-type: none"> <li>• Location of unmetered load.</li> <li>• Where the load is operated intermittently (for example Streetlights) the method of operation (ripple control, photo cell operated, etc).</li> <li>• Anticipated daily or annual hours of operation.</li> </ul> <p>Contact believes this rule should be expanded to include the provision of this additional information to the Distributor as part the connection of unmetered load process.</p>
<p>Rule 14.1 of Part E</p>	<p>This rule requires that, for shared unmetered load to be permitted that 1 trader must accept responsibility and to then nominate ICPs across which this load is to be shared. However the distributor is in the best position to nominate the ICPs across which the load is to be shared.</p> <p>Contact recommends that this rule be amended to reflect that the distributor be the party to nominate the ICPs across which the load is to be shared.</p> <p>Furthermore Contact is concerned that the rules for Shared unmetered load are inefficient and cumbersome. Contact recommends that the Commission schedule a fundamental review of Parts E &amp; J with a view to updating the rules for Shared unmetered load so that no new connections of this type are accepted under this rule.</p>
<p>Rule 17 of Part E</p>	<p>Contact is interested to know how a trader is to accept responsibility for a Distributor ICP representing shared unmetered load and how this will be recorded within the registry.</p>

Rule 19 of Part E	<p>Contact questions the need for a formal process of identifying and correcting Retailer related discrepancies within the registry. Contact believes the incentive of ICP days scaling is a sufficient driver to ensure the registry always has accurate information relating to reconciliation and market settlement.</p> <p>Contact does not believe there is enough clarity around what is expected from traders and the discrepancy reporting process should not sit within the rules. This was the reason the rule was dropped under global reconciliation given that it is difficult to monitor and that discrepancy error types were not well defined. The evidence of this was clear from the numbers of discrepancies reported by participants to the Registry.</p> <p>It would be more beneficial for industry participants to have a guideline to ensure attention is given to specific discrepancy types and the impact of not regularly monitoring such events.</p> <p>Any additional reporting of discrepancy requirements are likely to result in additional costs of compliance without adding material benefits to the reconciliation and settlement process.</p>
Rule 1.1.3, Schedule E1 of Part E	<p>Contact believes that the introduction of shared unmetered load has been a burden on traders and recommends that the industry agree to phase out this type of connection. The amount of time and effort involved in correcting discrepancies and customer disputes significantly outweighs the benefits of managing this load. Contact recommends that a clause is added to ensure no new shared unmetered load is permitted from the date of the new rules going live.</p>
Rule 1.1.3.2, Schedule E1 of Part E	<p>The obligations described in this rule for a point of connection between an embedded network and its parent network do not identify the information normally provided by the trader to the registry for other points of connection, namely:</p> <ul style="list-style-type: none"> <li>• Meter installation category.</li> <li>• Primary metering contact</li> </ul> <p>To ensure transparency Contact believes these fields need to be also included as required distributor items under this rule.</p>
Rule 2.1.6, Schedule E1 of Part E	<p>Contact considers this rule should be amended to explicitly state that the price Category [code] assigned to an ICP is to be a single code.</p>
Rule 2.1.7, Schedule E1 of Part E	<p>Contact considers this rule should be amended to explicitly state that a Chargeable Capacity value is only to be applied where it is the value directly applied to the calculation of a fixed line charge component for the ICP.</p>

<p>Rule 2.1.8, Schedule E1 of Part E</p>	<p>Contact considers this rule should be amended to explicitly state that the Installation Details field is only to be populated where additional information to Price Category code and Chargeable Capacity value are required to unambiguously identify the fixed line charges applicable to the ICP.</p>
<p>Rule 3.2, Schedule E1 of Part E</p>	<p>Contact considers this rule is unreasonable in its application.</p> <p>Distributors do not have the same requirements to ensure ICPs are populated on the registry (Rule 2.2, Schedule E1 of Part E – soon as practicable). A potential outcome is that reconciliation participant is not able to update the retailer attributes for an ICP that does not exist on the registry. However it is the reconciliation participant that will be in breach of the rules.</p> <p>The Registry currently does not allow for forward dated events. Furthermore, while participants know most of the ICP attributes listed in Rule 3, the actual event date also required for the population of this information is not confirmed until the site is physically electrically connected.</p> <p>In addition, where participants use NSP residual derived profiles to reflect time of day specific periods the use of these profiles is not known until after:</p> <ul style="list-style-type: none"> <li>• The Distributor responsible for the creation of the ICP assigns a Price Category code to allow Reconciliation Participants the ability to assess metering requirements. Currently Distributors are not required to provide this information on the registry under a specified timeline (Rule 2.2, Schedule E1 of Part E – before electricity is traded at the ICP) that would allow reconciliation participants adequate time to then meet their obligations.</li> <li>• A decision is made as to the meter configuration (single register – anytime meter, multi register – day / night meter, controlled meter) that is to be installed.</li> </ul> <p>Contact does not consider this proposed rule change will provide any significant benefit for the market but is likely to result in unnecessary registry updates to retailer events as retailers try to correct best guesses and also try to meet the requirements under Rule 19 of Part E.</p> <p>Contact has previously submitted in prior rule change consultations that the current impractical requirement for participants to update the registry within 3 business days from when a trader commences supply is too tight and recommends that the timeline should be moved to 10 business days to allow for sufficient time for paperwork to return from the field to ensure accurate initial population of information to the registry. If the requirement to populate the registry remains at less than 10 business days then participants will require their field contractors to invest in costly real time electronic transmission of information technology in order to comply. It is likely that this cost will eventually end up being passed onto customers without delivering any additional benefits. Contact believes that moving this timeline requirement to 10 business days will not adversely impact the market.</p>

<p>Rules 4.5 &amp; 4.7, Schedule E1 of Part E</p>	<p>Contact has identified a discrepancy between the interpretation of event date for status changes between the Registry Functional Specification and this rule.</p> <p>Clause 4.5 of the Registry Functional Specification states “The event date defines the date from which the attribute values of the event should apply. There is no end date. The state defined by the attribute values of an event for an ICP continues until a new event of the same type supersedes it. By convention, all events are deemed to occur at 00:00:00 on the day of the event date and to end at 23:59:59 on the day before the event date of the next event of the same type”.</p> <p>However in Rules 4.5 &amp; 4.7, Schedule E1 of Part E, it is unclear as to when a change of ICP status is to be reflected in the registry (at the beginning or end of the day). This ambiguity around the event dates for a change of ICP status can impact Historical Estimate calculations and also ICP Days calculations by Reconciliation Participants.</p> <p>Contact recommends that these rules be clarified in regards to explicitly stating how these events are to be reflected on the registry.</p>
<p>Rule 4.6A, Schedule E1 of Part E</p>	<p>Contact recommends that this be amended to require Distributors to initially inform the trader who requested the ICP identifier, giving the trader an opportunity to rectify the anomaly, prior to notifying the Market Administrator.</p> <p>Contact would hope that distributors and reconciliation participants would have sufficient processes and communication channels in place to notify parties of potential situations such as the non claiming of an ICP on the registry.</p>
<p>Rule 5.4, Schedule E1 of Part E</p>	<p>Contact agrees with the need to formalise the format of Loss Category Codes. However the Registry Functional Specification already stipulates that Loss Category Codes must be Alphanumeric (7 Characters) which would have addressed the issues that Contact has experienced to date with numeric only loss codes. Contact believes that ratifying the Registry Functional Specification requirements of an Alphanumeric code where at least 1 character must be an alpha character within this rule will address the issues experienced to date without impacting those distributors who currently comply with the functional specification requirements.</p> <p>Contact does not consider that it is necessary to mandate a leading “L”, rather that loss category codes must have a leading alpha and not a leading zero. To force a change to “L” for all current alpha-numeric loss codes is unnecessary.</p>

<p>Rule 5.8, Schedule E1 of Part E</p>	<p>Contact disagrees with this rule.</p> <p>The transfer of ownership of a network is a sufficiently significant event for the market and therefore should meet the same standards listed under Rule 5</p> <p>Contact recommends that this proposed rule be removed.</p>
<p>Rule 5A.7, Schedule E1 of Part E</p>	<p>Contact disagrees with this rule.</p> <p>The transfer of ownership of a network is a sufficiently significant event for the market and therefore should meet the same standards listed under Rule 5A</p> <p>Contact recommends that this proposed rule be removed.</p>
<p>Rule 6.1, 6.2, 6.3, Schedule E1 of Part E</p>	<p>Contact agrees with these rules</p>
<p>Rule 6.4, Schedule E1 of Part E</p>	<p>Contact disagrees with this rule as using the same coding convention on every price category code would seem to largely negate the purpose of having a coding convention.</p> <p>With that in mind, Contact questions the benefits associated with this rule, particularly when considered against the additional work required to incorporate the proposed changes.</p> <p>Contact recommends that this proposed rule be removed.</p>
<p>Rule 6.5, Schedule E1 of Part E</p>	<p>Contact agrees with this rule in principle, particularly as retailers have timeframes they must meet with respect to communicating price changes to customers.</p> <p>However, Contact suggests that there may be inadvertent negative side effects for customers. For instance, in situations where a customer has requested a change to a Low User load group, or a downgrade in capacity in order to reduce prices, it would not be in their best interests to have to wait in excess of two months for the change to take effect.</p> <p>In light of this, Contact suggests that the following be added: "For clarity... this rule does not apply where an alternative time frame has been agreed to by the applicable retailer."</p>
<p>Rule 6.6, Schedule E1 of Part E</p>	<p>Contact disagrees with this rule.</p> <p>The transfer of ownership of a network is a sufficiently significant event for the market and therefore should meet the same standards listed under Rule 6.</p> <p>Contact recommends that this proposed rule be removed.</p>

<p>Rule 8, Schedule E1 of Part E</p>	<p>Contact believes that this rule is incomplete in relation to the application of seasonal adjustment shape values where the creation of a NSP is in relation to the creation of an embedded network and existing ICPs (on a network extension) are to be transferred to this new NSP.</p> <p>The result of this transfer of existing ICPs from the parent network is that any historical estimate calculation involving validated meter readings that span the creation of this new embedded network will be incorrect. This historical estimate calculation will be impacted by the stepped change in seasonal adjustment shape values between the parent network balancing area values and the new embedded network balancing area values.</p> <p>While the application of UFE by the Reconciliation Manager will attempt to redistribute consumption information where reconciliation participant's historical estimate calculation cannot, this redistribution using the global UFE methodology is unlikely to be equitable where participant's market share between parent network and embedded network are different.</p> <p>To ensure reconciliation participants are not provided with step seasonal shape anomalies which adversely impact their ability to meet their initial submission accuracy obligations under Rule 2.2.3, Schedule J3 of Part J, consistent seasonal adjustment shape values need to be provided across the transition date of the NSP for these affected ICPs.</p>
<p>Rule 8.2, Schedule E1 of Part E</p>	<p>The wording used within this rule is unclear. The current wording states "The notification required by sub clause 1 must be given by: - <i>if the...</i>". Contact suggests that each sub clause (8.2.1, 8.2.2, 8.2.3, 8.2.4, 8.2.5) should begin "where the...", or alternatively shift the responsible party to the front of each subclause.</p>
<p>Rule 13.2, Schedule E1 of Part E</p>	<p>Contact does not consider that the notification requirements described in this rule is adequate. Contact interprets the term acquisition as the point at which the purchaser acquires formal ownership of an asset and the seller has received payment via a transfer of funds between parties. This rule in its current format can allow a notification to transfer ownership within 3 business days of the actual transfer which is inadequate for participants to enter into agreements with the new network owner.</p> <p>Contact believes that the notification requirement should be at least 3 months prior to the proposed acquisition date to allow adequate time for agreements between the new network owner and traders to be negotiated and agreed prior to the transfer of ownership of this network. Furthermore it allows time for traders to make all the necessary changes to their systems, processes and service provider arrangements to support trading on the new network.</p>

<p>Rule 9.2.1, Schedule E1 of Part E</p>	<p>Contact does not believe that the situations surrounding interconnection points between local and embedded networks are sufficiently unique to not require 1 calendar month's notification to affected participants.</p> <p>Contact recommends that this proposed rule be removed.</p>
<p>Rule 14.2, Schedule E1 of Part E</p>	<p>Contact questions why the Registry needs 3 business days to publish an updated NSP identifier schedule when the Reconciliation Manager has only 1 business day to provide details of a new NSP to the Registry.</p> <p>Contact suggests that for consistency Rule 14.2 should be amended require the same notification and publication timeframes for both the Reconciliation Manager and the Registry.</p>
<p>Schedule E1A of Part E</p>	<p>Contact believes that there is a step missing out of the proposed process to transfer a NSP between distributors. Seasonal shape adjustment files can be affected by this process and consideration needs to be given as to whether these shape files require either republishing under the new balancing area and Distributor participant codes, or require seasonal adjustment shapes to be recalculated for periods prior to the transfer so that no stepped change in seasonal shape values occur.</p>
<p>Rule 1.2A.1.2, Schedule E2 of Part E</p>	<p>Contact understands the driver to reduce the time taken to switch ICPs between retailers, however we do not believe this proposed rule in its current format will achieve sufficient benefits to outweigh the likely increased costs to comply and the reduction in accuracy of switch reads as a result. It is critical not to over emphasize quick switches at the expense of quality, as both participants and customers are adversely affected by poor quality switches.</p> <p>The implementation of such a rule reduces the opportunity to ensure issues such as wrong property/ICP switches can be addressed before the switch process is completed. In addition 3 business day switching time frames effectively removes opportunities for losing traders to collect an actual read (where it is required for compliance or to ensure a smooth switch) to complete the switch unless Advanced Metering is in place. This will result in increased switch read disputes which take significant resources to resolve and adversely impacts the customer experience of switching traders unless the current tolerance for disputing switch reads (1.4.2, Schedule E2 of Part E) is increased to reflect the shared risk between parties associated with reducing the switch timeframes. The current resources to progress switch read disputes to completion are significant and any additional increase in the quantity of switch read disputes will result in participants incurring additional costs that will eventually be passed onto customers through increased cost to serve.</p> <p>Contact also believes that proceeding with a 3 day switch will conflict with rule 4A, Schedule E2 of Part E and have a negative impact on Registry data where a withdrawal can only be issued prior to the event date. This will increase the amount of redundant data on the Registry where traders are</p>

	<p>required to re-request switches instead of having the option of withdrawing the original incorrect events. This also affects Registry management where redundant events could block updates that the previous trader may wish to make. The events will need to be inserted historically instead of added or replaced.</p> <p>This proposed rule change is also inconsistent with the requirements under The Door to Door Sales Act 1967 for parties to provide a sufficient Cooling off Period of time to customers before the actual transfer of traders is completed. The Door to Door Sales Act 1967 provides customers a 7 day window to cancel any agreement with a prospective trader and remain with their current trader. Given that once a switch is complete it cannot be withdrawn (Rule 4.5, schedule E2 of Part E), any customer who chooses to cancel such an agreement within the 7 days period but after a switch is completed now will have to formally switch back to its original trader but under the 23 business day switch timetable. Contact considers this situation is unacceptable to both customers and traders as well as in conflict with other legislation.</p> <p>Contact recommends the following as an alternative to this proposed rule:</p> <ul style="list-style-type: none"> <li>• Provide for requested date switches, consistent with the Gas (Switching) Rules 2008 so that customers wishing to switch both fuels are able to acquire the same switch date from the gaining trader. The requested date must be at least 7 business days from the date of request. This will address the Door to Door Sales Act 1967 requirements to provide adequate time for customers to decide whether to cancel this request. It also ensures the customer's expectation can be met in terms of a switch or transfer date between traders. And:</li> <li>• Amend Rule 1.4.2, Schedule E2 of Part E by increasing the current switch read dispute threshold of 200kWh per to be 500 kWh across all meters at an ICP level. And:</li> <li>• Amend Rule 4A, Schedule E2 of Part E to allow for a request to withdraw a switch upto the point immediately prior to when the gaining trader has produced the first bill for the ICP in Question.</li> </ul>
<p>Rule 1.2A.2, Schedule E2 of Part E</p>	<p>Can you please clarify the wording – how many traders are involved here, if more than one then which one is to ignore event dates.</p> <p>Contact believes that this rule adds unnecessary complexity to the switching process and should be removed or amended. It should be at the losing Trader's discretion to delay the switch for any reason, so long as the switch is completed within the industry timeframe specified. Contact also notes that this rule would not be ideal and would add further complexity if the switch timeframes remained at 3 business days</p>

Rule 2, Schedule E2 of Part E	<p>Contact recommends that this rule be updated to clarify when a switch qualifies as a switch move.</p> <p>The current rule does not require the gaining trader to validate when their proposed customer began occupancy of the ICP by one of the following means:</p> <ul style="list-style-type: none"> <li>• Viewing a copy of a property sale &amp; purchase agreement.</li> <li>• Viewing a copy of a tenancy agreement</li> <li>• Confirmation that the customer involved is an existing customer of the gaining retailer that is changing address.</li> <li>• Viewing a copy of a business sale and purchase agreement.</li> </ul> <p>Contact considers this is an important step required to ensure correct reconciliation and market settlement of volumes between traders.</p> <p>Where a gaining trader cannot validate the date at which a new customer began occupancy of an ICP then it should be the losing retailer that determines either:</p> <ul style="list-style-type: none"> <li>• The date at which this ICP is to switch. This date should also be allowed to precede the gaining traders proposed event date.</li> <li>• If the losing trader has the ICP in question flagged as occupied within its systems then the losing trader may reject this proposed switch move as a wrong switch type. The gaining trader may re-request this ICP but using the standard switch process.</li> </ul> <p>In order to ensure that the correct switch process is used by traders Contact recommends that the terms Switch and Switch Move become defined terms under the EGRs. Contact suggests the following definitions of Switch and Switch Move become part of the EGRs:</p> <p><b>“Switch”</b> means the process by which once a trader has entered into an unconditional agreement with a customer or embedded generator, the responsibility for the supply of electricity for an ICP to transfer between traders.</p> <p><b>“Switch Move”</b> means the process by which once a trader has entered into an unconditional agreement with a customer or embedded generator who has recently begun or is about to begin occupancy of an ICP, the responsibility for the supply of electricity for an ICP to transfer between traders. The ICP identified must be flagged in the losing trader’s system as vacant and the gaining trader must verify the occupancy date of its customer for this switch type to be used.</p>
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<p>Rule 3.4, Schedule E2 of Part E</p>	<p>Contact suggests that this rule be amended to provide that the gaining retailer has 1 calendar month from the actual event date to update the Registry. Given that for HHR switching, the gaining trader must independently source meter set up information outside of the switch process, the 3 business day notification period is often impacted by the collection and verification of this meter configuration information.</p> <p>As HHR ICPs are traditionally billed by calendar months there is minimal market impact by extending the registry notification process.</p> <p>“Three” should be amended to “3”.</p>
<p>Rule 4A, Schedule E2 of Part E</p>	<p>Contact is very concerned with the implications of this rule when combined with the proposed Rule 1.2A.1.2, Schedule E2 of Part E (80% event dates established no more than 3 business days after date of notification).</p> <p>Where a wrong property issue is identified after the switch is completed or a customer decides to remain with the current retailer under the cooling off period provision under the Door to Door Sales Act 1967, then this rule does not allow a switch withdrawal to occur to correct the situation once a switch has been completed.</p> <p>30% of all switch requests where Contact is involved are currently withdrawn under the current rules and a number of these occur once a switch has been completed. Given the number of customers who rescind their decision to switch to an alternative retailer, the processes to meet the customer’s wishes should be as flexible as possible.</p> <p>Furthermore, if the losing retailer was to attempt to switch back an ICP incorrectly transferred to another retailer for the above reasons then the event date of this switch back is at the discretion of the new retailer and could take up to 23 business days, further impacting the customer involved.</p> <p>Contact recommends that this proposed rule is not implemented or be amended to allow a switch withdraw request to occur upto the creation of the first bill by the gaining trader.</p>

<p>Rule 3.1 (Option 1) of Part J</p>	<p>Contact believes that this option should cover all profiles rather than only the Commission owned profiles as currently described in this proposed rule change.</p> <p>If the Reconciliation Manager is required to verify whether a Participant is authorised to use an NSP derived or dynamic profile as part of any trading notification then this validation can be achieved by the use of a standing data table of approved profile codes and the participants authorised to use these complete with effective dates. The Market Administrator can then provide updates to the Reconciliation Manager as required when changes to the approved profile register are made and also when a participant grants another party authority to use one of their profiles.</p> <p>If the proposed rule change is not amended to cover all profiles then this will discourage participants to develop new profiles to more accurately reflect actual consumption patterns for consumer groups because of the risk of technically breaching a rule that has no real market impact.</p>
<p>Rule 4A of Part J</p>	<p>Contact believes that this rule will not meet its intended purpose. This rule assumes that embedded generators are familiar with the both the EGRs and the Reconciliation Manager function. Contact's experience with embedded generators is that this is not the case and it will be the Reconciliation Participant responsible for the ICP on the registry that will effectively provide the notification required to the Reconciliation Manager.</p> <p>This notification requirement will be further complicated where ICPs with embedded generation (such as small scale photovoltaic generation) switch between traders as the new trader will not be aware if such a notification has been previously provided and will again engage the customer to determine this as part of the switch process.</p> <p>Contact recommends that this rule be amended to require the Distributor to provide this notification to the Reconciliation Manager on behalf of the embedded generator as the Distributor should be aware of any connection to its network that may generate at any time as part of the connection agreement process.</p>
<p>Rule 8.3.3 of Part J</p>	<p>Contact believes that this rule requires amendment as a result of the proposed new rule 10.7 of Part J allowing for the Reconciliation Manager to correct information if directed by the Board.</p> <p>Rule 8.3.3 of Part J should now be subject to Rule 10.7 to reflect the situation where a participant may have submitted incorrect HHR submission information as part of its 7 month revision. While this error is able to be corrected as part of the 14 month revision, the impact to the seasonal adjustment shapes would mean all participants 14 month NHH submissions would be incorrect as a consequence.</p>

<p>Rule 10.7 of Part J</p>	<p>Contact believes the wording of this proposed new rule is ambiguous and requires clarification as to who will direct the Reconciliation Manager to correct information.</p> <p>Rule 10.6 of Part H states that the Rulings Panel is the entity that will direct the Reconciliation Manager to correct information. However Rule 10.7 of Part J states that the Board will direct the Reconciliation Manager to correct information.</p> <p>Contact considers that such direction must be able to be given without undue delay once the material error has been identified, accordingly it should be the Board that directs the Reconciliation Manager. Where the issue has been referred to the Rulings Panel before such a direction is considered appropriate, it would be appropriate for the Rulings Panel to confer with the Board to ensure that any settlement determined by the Rulings Panel which requires re-opening of reconciliation/settlements is able implemented by direction from the Board to the Reconciliation Manager.</p> <p>It is noted that the Gas (Downstream Reconciliation) Rules 2008 provides for the gas equivalent of the Board (Gas Industry Co) to provide such a direction as the Industry Body to the gas equivalent of the Reconciliation Manager (Allocation Agent) provided its assessment of the likely market impact of incorrect information meets published thresholds.</p> <p>Contact recommends that this proposed rule is amended to provide for the Electricity Commission appoint an Industry Body (such as the Market Administrator) to be authorised to provide the Reconciliation Manager with the direction to correct information and for the Clearing Manager to conduct additional wash ups and provide revised invoices.</p>
<p>Rule 12.5 of Part J</p>	<p>Contact considers that this rule has to be amended to allow parties to raise disputes within 24 months of the date of issue of any invoice so that it is consistent with Rule 10.7 of Part H</p>
<p>Rule 20.3 of Part J</p>	<p>Contact recommends that this rule be amended to reflect that a register of participant identifiers is now published by the Commission on their website.</p>
<p>Rule 3C.1, Schedule J1 of Part J</p>	<p>Contact recommends that this rule be amended to reflect while it is preferable for a full audit of a new system or process prior to its implementation this is not practicable in all situations.</p> <p>Contact believes that an initial desktop audit of the proposed new system functions and processes prior to implementation of the new system, followed up by a physical audit of the new systems and processes within 3 months of the implementation of this new system or process, would provide a more efficient and accurate mechanism of auditing and certifying a participant's new system or process.</p>

<p>Rule 8, Schedule J1, of Part J</p>	<p>Contact recommends that this rule is amended to explicitly provide for the Board to call for event audits across all participants where it believes that there is an underlying issue affecting reconciliation or settlement of the market.</p> <p>Contact is concerned about the high levels of UFE currently identified within a number of network areas without adequate explanation. High ongoing levels of UFE is a barrier to reconciliation participants considering entering or continuing to trade within a network area, it also causes unpredictable costs of trading. In order to address this issue Contact would encourage the Board to arrange for event audits to attempt to identify the cause of this unacceptably high UFE currently identified across a number of network areas. This provision is included in the Gas (Downstream Reconciliation) Rules 2008.</p>
<p>Rule 5.3, Schedule J2 of Part J</p>	<p>Contact believes that full compliance of this rule cannot be achieved in a number of instances where customer's tenure with a retailer is relatively short due to the current competitive nature of electricity retailing. Contact does not believe there is any material market impact in these instances. Contact recommends that this rule be amended by allowing for exceptional circumstances to apply in the same circumstances as Rule 5.4</p>
<p>Rule 5.5, Schedule J2 of Part J</p>	<p>Contact believes that full compliance of this rule cannot be achieved in a number of instances where the number of ICPs involved is small (say less than 100) and there are exceptional circumstances. Contact recommends that this rule be amended to:</p> <ul style="list-style-type: none"> <li>• Allow for a minimum number of ICPs per NSP before this rule is to apply.</li> <li>• Allow for exceptional circumstances to apply in the same circumstances as Rule 5.4.</li> </ul>

<p>Rule 14.2, Schedule J4 of Part J</p>	<p>Contact sees no issue with Distributors having access to this information if it is to be used to validate reasonable long term alignment (rolling 12 months) between the consumption reported by Retailers for network billing purposes and the consumption submitted to the Reconciliation Manager for energy settlement purposes.</p> <p>It needs to be noted however that this should not be misrepresented as providing an expectation of alignment given the different needs and base information – network reporting driven by network pricing and annual revenue requirements, and energy reporting and reconciliation driven by half hour volatility in spot market prices requiring accurate allocation of consumption to half hour trading periods.</p> <p>However Contact believes the provision of this information is a commercial arrangement between the Distributor and the Retailer and should not require to be regulated under the EGRs.</p> <p>In addition the proposed rule, as it is currently framed, will result in all Distributors receiving reports that only a few Distributors actually require. The vanilla approach to the publication of these reports has the potential to result in incorrect comparisons of these datasets by some parties.</p> <p>Contact recommends that this rule be amended to require Distributors to request the receipt of these reports from both the affected Reconciliation Participants and the Reconciliation Manager.</p>
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