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Vector Limited
101 Carlton Gore Rd
PO BOX 99882
Auckland 1149
New Zealand
+64 9 978 7788 / vector.co.nz

Australian Energy Market Commission
Level 15
60 Castlereagh Street
Sydney NSW 2000

Submission on the Review of the Regulatory Framework for Metering Services – Draft Report

Introduction

1. This is Vector Limited's (Vector)[1] submission on the Australian Energy Market Commission's (AEMC) *Draft Report – Review of the Regulatory Framework for Metering Services* (the Draft Report), released on 3 November 2022. Vector appreciates the AEMC's active engagements with stakeholders via the Review Reference Group and Sub-Groups since their establishment and in the development of the options and recommendations in the Draft Report.

2. Vector strongly supports the AEMC's recommendation to accelerate the deployment of smart meters in the National Electricity Market (NEM) – which has not met stakeholder expectations – and agrees with the recommended acceleration targets.

3. We welcome the AEMC's view that the current industry structure remains the appropriate arrangement to achieve accelerated deployment, and that retailers and metering parties will remain responsible for metering services for small consumers. Vector has been consistent in its view that the benefits of smart meters are best delivered in a competitive environment where market competition and innovation that benefits consumers can flourish.

4. In this submission, we recommend some features that can be incorporated into the AEMC's preferred option for accelerated deployment (Option 1 – distribution network service providers [DNSPs] to coordinate a legacy meter retirement plan) to help ensure an efficient rollout. However, we consider Option 3 (retailers planning and replacing legacy meters with smart meters in line with the acceleration target) to be a more workable approach that avoids several issues that can arise under option 1. We make suggestions on how annual targets could be set under Option 3.

5. We broadly agree with the AEMC's recommendations to improve the efficiency of metering installation processes, support customers through the transition process, and unlock further consumer benefits through better smart meter data access. We provide suggestions and recommendations for further improvements to some of the recommended options, rule changes, and actions in the Draft Report to better achieve these objectives.

[1] Vector's Australian and New Zealand smart metering business – Vector Metering – is an accredited Metering Provider and Metering Data Provider, and a registered Metering Coordinator, in Australia's National Electricity Market and the equivalent in New Zealand. Vector Metering provides a cost-effective end-to-end suite of energy metering and control services to energy retailers, distributors, and consumers.

In December 2022, Vector announced that it has selected QIC Private Capital Pty Limited as preferred partner for Vector Metering joint venture, following conclusion of a strategic review. Vector has entered into a conditional agreement with QIC, under which the parties expect to finalise arrangements in the first quarter of 2023 for the sale of a 50% interest in Vector Metering to investment vehicles managed and advised by QIC.

6. We also support the AEMC's recommendation for the provision of a basic Power Quality Data (PQD) service built on industry agreed formats and standards, to be provided by all metering providers to DNSPs, underpinned by commercial agreements between these parties that reflect the 'beneficiary pays' model.

7. We set out below our responses to the consultation questions, capturing the above suggestions – for the AEMC's consideration.

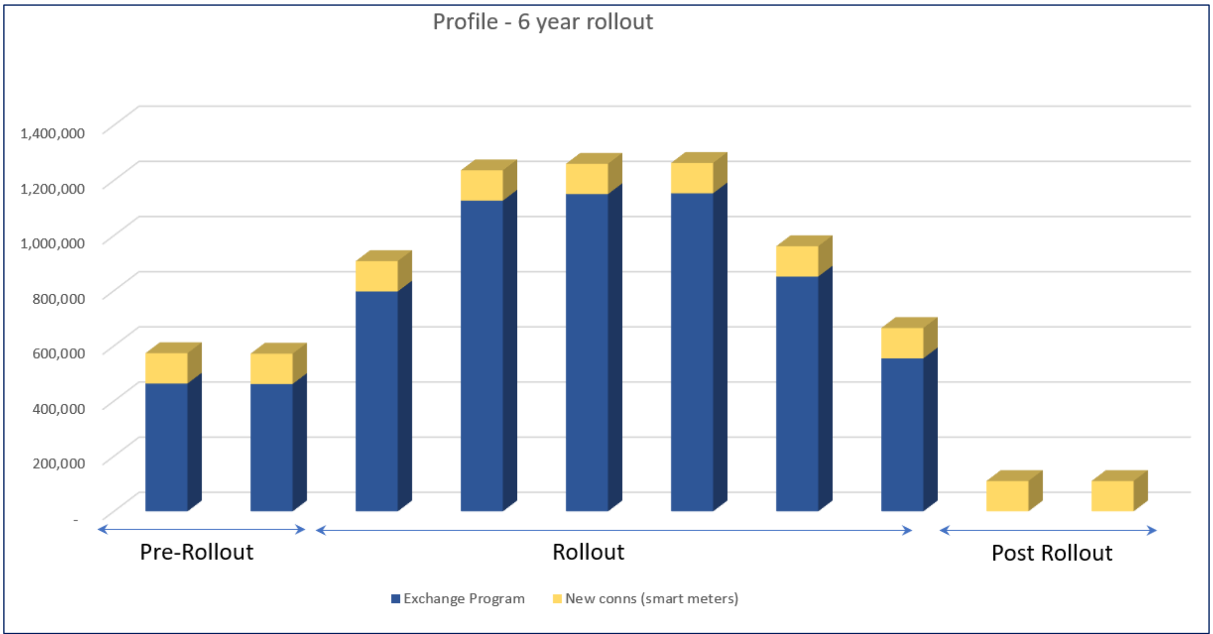
Responses to the consultation questions

QUESTION 1: IMPLEMENTATION OF THE ACCELERATION TARGET
1. Do stakeholders consider an acceleration target of universal uptake by 2030 to be appropriate?
2. Should there be an interim target(s) to reach the completion target date?
3. What acceleration and/or interim target(s) are appropriate?
4. Should the acceleration target be set under the national or jurisdictional frameworks?

8. Vector agrees with the AEMC that the replacement of legacy meters with smart meters should be accelerated to unlock greater consumer benefits and support ongoing reforms.

9. As raised in Vector's submission (dated 28 October 2021) on the Review's Directions Paper, it is important that any accelerated rollout delivers a consistent flow of meter exchanges and avoids 'boom and bust' cycles.[2] In our view, annual targets that considers the need for a steady ramp up over the initial years and peaking toward the middle and later years will deliver a rollout that is practical and achievable. Figure 1 shows a profile that meets the criteria for a steady ramp up.

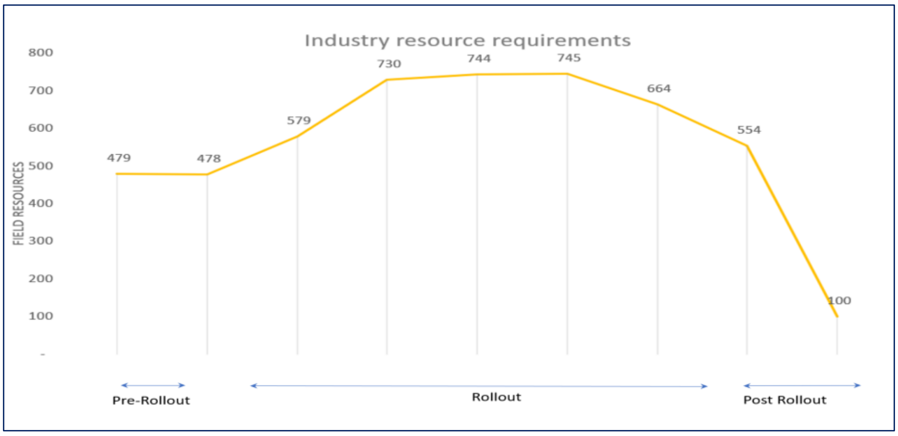
Figure 1. Indicative profile for an accelerated rollout until 2030



2 https://www.aemc.gov.au/sites/default/files/2021-11/Rule%20Change%20Submission%20-%20EMO0040%20-%20Vector%20-%2020211028.PDF, paragraphs 79-80

10. Figure 2 shows the estimated resources required to meet the demand profiled in Figure 1.

Figure 2. Estimated resources for an accelerated rollout



11. Metering Providers (MPs) require clear visibility of the rollout profile to ensure that resources will be available to meet demand. We understand that all MPs have experienced issues at the commencement of the *Power of Choice* reforms when expected demand for metering work did not materialise, resulting in field resources ceasing work and causing significant reputational damage to the industry. Having clear visibility of the demand over the entire accelerated period is crucial to avoid these issues.

12. To deliver a rollout profile that is practical and achievable, gives visibility of demand across the whole programme, and avoids boom and bust cycles, we **recommend** that interim targets for each year of the accelerated programme be set before it commences. Table 1 estimates the percentage of legacy meters that would be exchanged each year by the relevant industry participants to deliver the profile shown in Figure 1.

    Note: Volumes of installations are based on our estimates of the current size of the legacy meter fleet and what this is projected to be at the start of 2025. As accurate data is not publicly available – a long running issue that we hope may soon be addressed under the Energy Security Board (ESB) Data Strategy[3] – we **recommend** that these percentages be updated once the true size of this population is made available by the Australian Energy Market Operator (AEMO).

Table 1. Estimated % of legacy meters that would be exchanged each year

Rollout year	EOY Installation Target - % of baseline (2025)	Approximate Volume installed each year (000s)
Year 1	14%	800
Year 2	34%	1,120
Year 3	54%	1,145
Year 4	74%	1,147
Year 5	89%	880
Year 6	100%	610
	Total	5,702

3 https://esb-post2025-market-design.aemc.gov.au/data-strategy

13. We **recommend** that the measurement of progress against targets should be based on a count of metering installations with smart meters *deployed* by a retailer, rather than a point-in-time snapshot of how many of the retailer's customers have smart meters. This will better reflect work that retailers have done to meet their obligations and will cater for customer churn between retailers, i.e. winning and losing customers with smart meters will not affect retailers' targets.

14. We support the acceleration targets being proposed in the Draft Report (i.e. in the National Framework).

QUESTION 2: LEGACY METER RETIREMENT PLAN (OPTION 1)

1. *Do stakeholders consider this approach feasible and appropriate for accelerating the deployment of smart meters?*
2. *Do stakeholders consider the Commission's initial principles guiding the development of the Plan appropriate? Are there other principles or considerations that should be included?*
3. *If this option is adopted, what level of detail should be included in the regulatory framework to guide its implementation?*
4. *Do stakeholders consider a 12-month timeframe to replace retired meters appropriate? Should it be longer or shorter?*
5. *Are there aspects of this approach that need further consideration, and should any changes be made to make it more effective?*

15. Under Option 1, the DNSP is in control of the annual schedule of metering installations that are to be visited – that is to say, the year that meters at a legacy metering installation should be exchanged. It is our view that Option 1 can result in an efficient accelerated rollout if the following features are incorporated into this option:

    - <u>Annual rollout plans must retire national metering identifiers (NMIs) on a geographical basis but in a manner that considers the realities of labour/manpower constraints.</u> This will result in the lowest cost for MPs as travel cost for field resources is minimised. However, any plan must be designed with input from MPs so that localised resourcing constraints are considered in determining the volume of retirements over a period of time. Without it, MPs will not achieve the installation efficiency levels required to reduce the costs of meter exchanges and meet industry targets.

    - <u>DNSPs must publish the complete plan indicating the year of replacement for each legacy metering installation before the start of the rollout</u>, i.e. by July 2024 at the latest. This will provide retailers with clear visibility of the upcoming demand and allow them to engage with their MPs who can then plan and allocate resources adequately.

    - We agree with the proposal to handle meter churn where <u>retailers who become responsible for a metering installation that has been determined as due for replacement in that calendar year should have 12 months to replace the meter</u>.

16. As a geographically-organised rollout is critical for an efficient, practical, and achievable smart meter rollout, we also **recommend** that an alternative to the DNSP nominating individual NMIs for replacement would be for DNSPs to simply publish a set of postcodes each year. Retailers themselves would use the postcodes to determine the NMIs for exchange for that calendar year. This may be a simpler approach that would make it easier for DNSPs, retailers, and MPs to agree an accelerated rollout plan. Consideration of the industry-agreed annual interim targets would be required when nominating these locations,

e.g. due to size of the population, as well as input from MPs as to the availability of field resources in the area. It may be necessary to spread the replacement over several years in high density areas. This approach may also mean that DNSPs do not need to issue market B2B transactions (meter fault and issue notifications – MFINs), as proposed in the Draft Report. This way, retailers can select NMIs based on the published postcodes in Market Settlement and Transfer Solutions (MSATS). Reporting on progress to the Australian Energy Regulator (AER) could be centralised through AEMO.

QUESTION 3: LEGACY METER RETIREMENT THROUGH RULES OR GUIDELINES (OPTION 2)

1. *Do stakeholders consider option 2 feasible and appropriate for accelerating the deployment of smart meters? Are there aspects of option 2 that would benefit from further consideration?*
2. *Are market bodies the appropriate parties to set out the legacy meter retirement schedule?*
3. *If option 2 is adopted, should the meter retirement schedule be located in the rules, or guidelines developed by the AER or AEMO?*

17. Vector does not support Option 2 where regulators and/or market bodies determine the sequencing of accelerated meter replacements. We believe DNSPs, retailers, and MPs are best placed to develop a plan for a practical, flexible, and achievable rollout.

QUESTION 4: RETAILER TARGET (OPTION 3)

1. *Do stakeholders consider option 3 is feasible and appropriate for accelerating the deployment of smart meters? Are there aspects of option 3 that need further consideration?*
2. *If this option is adopted, what are stakeholders' suggestions on how retail market dynamics could be taken into consideration in both setting the uptake targets and monitoring performance?*
3. *Should the rules or a guideline outline only a high-level target (universal uptake by 2030 taking into account practicality of replacements) or more granular targets or interim targets?*

18. An alternative to Option 1 (where the DNSP determines the annual rollout schedule) is to place this responsibility on retailers. As in all the other options, the industry will first need to agree the annual rollout targets that retailers will be required to meet.

19. Under the "retailer target" option (Option 3), the industry-agreed target would be translated into a volume of meter exchanges that must be met or exceeded over the rollout period.

20. Table 2 below provides an example of the annual volume and percentage targets that a retailer would be subject to – to progress the rollout.

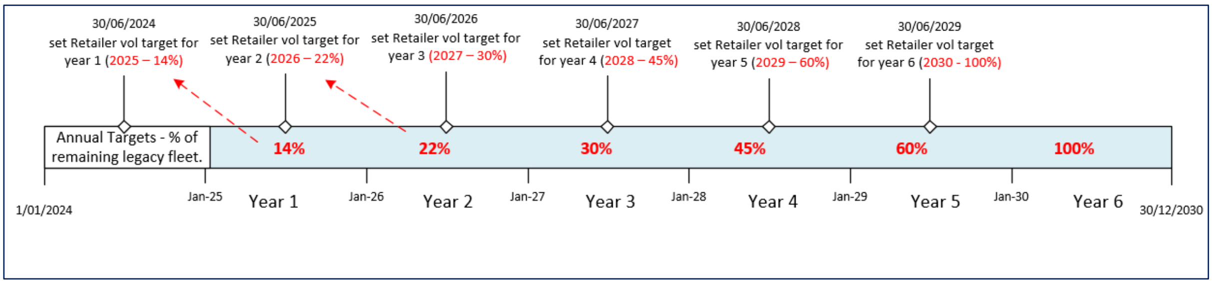
Table 2. Estimated installation targets over the accelerated deployment period

Rollout year	EOY installation target - % of baseline (2025)	Approximate volume installed each year (000s)	Approximate % of remaining fleet to meet target
Year 1	14%	800	14%
Year 2	34%	1,120	22%
Year 3	54%	1,145	30%
Year 4	74%	1,147	45%
Year 5	89%	880	60%
Year 6	100%	610	100%
	Total	5,702	

21. Each retailer would apply the target percentage against their customer base that have legacy meters and select the NMIs for replacement based on discussions with MPs. Retailers are likely to select NMIs that provide the largest benefits first but will also be subject to industry targets to ensure all meters are exchanged within the programme's timeframes.

22. We **recommend** that percentage targets be set six months prior to the commencement of the calendar year. This would provide good visibility of demand for the upcoming calendar year for both the retailer and their MPs, enabling them to determine an appropriate deployment plan that would 'level' the available resources. Any customers that churn away from the retailer will be excluded from the retailer's annual plan, and any customers acquired by the retailer after the volume target is determined will be reflected in the subsequent year's volumes. This approach is demonstrated in Figure 3 below.

Figure 3. Example of how annual installation targets could be set



QUESTION 5: STAKEHOLDERS' PREFERRED MECHANISM TO ACCELERATE SMART METER DEPLOYMENT

1. *What is the preferred mechanism to accelerate smart meter deployment?*
2. *What are stakeholders' views on the feasibility of each of the options as a mechanism to accelerate deployment and reach the acceleration target?*
3. *Are there other high-level approaches to accelerating the deployment that should be considered?*

23. Vector prefers Option 3 (retailer target) over option 1 (a retirement plan coordinated by DNSPs). While Option 1 is feasible, it has issues that appear complex and difficult to resolve. For example, how can a geographical rollout prepared by the DNSP avoid localised boom

and bust scenarios (by adequately considering available resources) when DNSPs are not aware of the MP's resourcing levels. Option 1 will also require changes to market B2B transactions and MSATS, which would be a 'sunk cost' once the rollout is completed.

24. In contrast, Option 3 is simpler, avoids the material issues associated with Option 1, and can be implemented and monitored without the need for new industry B2B infrastructure. A shortcoming of Option 3 is that DNSPs will incur higher costs as reading routes are not retired systematically. However, given the expected level of failed exchange attempts (Unable To Complete) that result in the legacy meter remaining for some time after the adjacent meters have been exchanged, it is our view that none of the options in the Draft Report will protect DNSPs from this issue.

25. Monitoring retailer performance can be performed by the AER, including using reports that can easily be provided by AEMO. These reports can determine the number of smart meters installed by each retailer against their pre-defined targets.

26. We **recommend** that the AEMC put in place incentives to encourage retailers to continue to install smart meters leading up to the commencement of any new regulatory obligations to accelerate their rollout. This is to avoid the situation experienced in 2016 preceding the commencement of the *Power of Choice* reforms in metering where metering work practically ceased as retailers waited for their new obligations to commence.

27. We further **recommend** that a credit system be devised where meters installed in 2023 and 2024 be counted towards retailers' targets for the first two years of the accelerated rollout.

QUESTION 6: FEEDBACK ON NO EXPLICIT OPT-OUT PROVISION

1. *Do stakeholders have any feedback on the proposal to remove the opt-out provision for both a programmed deployment and retailer-led deployment?*
2. *Are there any unintended consequences that may arise from such an approach?*

28. Vector supports the proposal to remove the regulatory requirement for retailers to offer customers to 'opt out' of having smart meters deployed in their premises. We support this arrangement for both the proposed programmed/accelerated deployment and continuing retailer-led deployment.

29. We **recommend** that the question of whether customers can refuse the installation of a smart meter be left for discussion between retailers and their customers. For practical reasons, regulators and the industry must accept that there will be a small number of customers who will resist the installation of a smart meter, for whatever reason(s). However, customers' rights need to be balanced with the requirement for compliant metering to be in place. We believe that retailers should be supported by the regulatory framework in insisting that a new interval meter be installed. However, the current arrangements of allowing remote communications to be disabled is available to any customers who have concerns regarding the use of remote technology.

30. We note the opaqueness of the current regulatory framework on whether retailers can insist that the customer accept the installation of a smart meter to address non-compliant (malfunctioning) metering situations. Currently, there are remedies for situations where a customer does not grant access to a meter reader to that customer's premises, or to the DNSP to access the metering installation. However, these do not include allowing the retailer to arrange a meter exchange. Clarifying this issue is, in our view, one of the key factors that would ensure a successful accelerated rollout.

QUESTION 7: REMOVAL OF THE OPTION TO DISABLE REMOTE ACCESS

1. Do stakeholders consider it appropriate to remove the option to disable remote meter access under acceleration?

31. It is self-evident that regardless of the policy that will be adopted, a very small (less than 0.01% to date) and potentially declining number of customers will have concerns about the use of their remote smart meter technology. We believe that the current approach of disabling the communications module and treating these sites as manually read meters should be retained to manage these customers even though higher reading costs will be incurred, which may be passed onto the customer. Allowing for the customer to request the remote communications to be disabled is a reasonable compromise in situations where the legacy meter is faulty and needs to be replaced and the customer does not want a communicating smart meter.

32. We **recommend** that the current obligations in the *National Electricity Rules* (NER) that are placed on retailers and Metering Coordinators (MCs) to maintain records related to customers requesting a type 4A (non-communicating) meter be reviewed. These obligations appear to be designed to ensure that retailers and MCs do not roll out manually read meters in preference to remote meters. Given the natural incentives for these parties to minimise the number of type 4A meters, these prescriptive record keeping requirements complicate business processes and, in our view, provide little benefit. We therefore do not see the need to retain these obligations.

QUESTION 8: PROCESS TO ENCOURAGE CUSTOMERS TO REMEDIATE SITE DEFECTS AND TRACK SITES THAT NEED REMEDIATION

1. Do you consider the proposed arrangements for notifying customers and record keeping of site defects would enable better management of site defects?

33. Vector broadly supports the proposed notifications advising the customer of defects that are impeding the installation of a smart meter that the customer must resolve; however, we believe that the process, as suggested in the Draft Report, can be improved. We **recommend** that the tagging of a NMI in MSATS to alert the presence of the customer site defect should occur earlier in the process, as suggested in the Draft Report. This should occur as soon as the defect is discovered rather than after the second notice has been sent to the customer so that all parties with an interest in the site are aware that work is required by the customer before a smart meter can be installed. We also question whether it is necessary to include detailed information about the notifications to the customer in MSATS. The key pieces of information are the date that the defect was registered, the nature of the defect (so any new retailers or MCs are aware of the issue that require resolution by the customer), and potentially the date the customer advises that the defect was resolved. Assuming that participants are generally fulfilling their obligations and are subject to non-compliance self-reporting requirements, and regular audits where applicable, it is unnecessary to log a date each time a reminder notice is sent.

34. In relation to the overall management of customer site defects, and as indicated in our previous submissions, we strongly believe this role should be assumed by the DNSP, not the retailer as proposed. In our view, the DNSP is best placed to manage customers where non-compliances are a barrier to the replacement of their legacy meters with smart meters, for the following reasons:

    - Under the NER, the DNSP – as the initial MC – is responsible for the metering installation while the legacy meter remains at the site (NER Cl 87.11). Responsibility for the metering installation does not transfer to the retailer and contestable MC until the legacy meter is successfully replaced.

- The DNSP is the only market role that is permanently associated with the site. The retailer, or a new MC, may change as the customer churns between retailers. Tracking the progress of defects (and proposed defect notices) will be more complex under a model where the retailer is responsible for this role, compared to one where this is performed by the DNSP.

- The DNSP has a perpetual commercial relationship with the customer at the premise via their connection contract. This can be used to enforce customer obligations. In contrast, a retailer has a commercial relationship with the customer only while they remain the financially responsible market participant (FRMP) for that site. Once customers transfer to another retailer, the relationship with the original retailer ceases.

- Having the DNSP take responsibility for managing the defect with the customer is a simpler construct that does not need to deal with the complexities introduced by meter churn and changing contractual relationships.

- Making the retailer (or MC or MP) responsible for notifying the market of the presence of a defect via MSATS will require retailers to be given the authority to update NMI information. This also requires new Consumer Administration and Transfer Solution (CATS) transactions to be built. In contrast, the DNSP already assumes the responsibility to maintain NMI level data and have market transactions that can easily be enhanced to update NMI details.

QUESTION 9: IMPLEMENTATION OF THE 'ONE-IN-ALL-IN' APPROACH

1. *Would the proposed 'one-in-all-in' approach improve coordination among market participants and the installation process in multi-occupancy sites?*
2. *Are the timeframes placed on each market participant appropriate for a successful installation process of smart meters?*
3. *Are there any unforeseen circumstances or issues in the proposed installation process flow and timeframes?*
4. *How should DNSPs recover costs of temporary isolation of group supply from all retailers?*
5. *Can the proposed role of the DNSP in the one-in-all-in approach be accommodated by the existing temporary isolation network ancillary services?*
6. *Which party should be responsible for sending the PIN in the context of the one-in-all-in approach?*

35. Vector agrees with the proposed 'one-in-all-in' approach to installing smart meters in multi-occupancy sites. We view the proposal in the Draft Report to be the most achievable of the options presented given the constraints of the regulatory framework, i.e. the commercial nature of the relationship between retailers and their MPs. However, dealing with multi-occupancy sites will be complex and will require a level of cooperation between retailers if the proposed one-in-all-in approach is to be successful. Retailers will need to put customers' interests ahead of their commercial interest if the impact to customers of multiple interruptions is removed or at least reduced. Without this co-operation, the proposed approach may not achieve the desired outcome.

36. For the one-in-all-in approach to work, we **recommend** that the following changes must be included in the regulations:

- DNSPs must be required to advise all FRMPs for NMIs that are impacted by the Temporary Interruption Group Supply (TIGS) of the scheduled date of the interruption and who the primary MC for the TIGS is (advised by the retailer requesting the TIGS).

- When advised by the DNSP that a TIGS has been scheduled for a NMI, retailers must be required to assign an MC and arrange for the required metering exchange to take place during that interruption, i.e. raise the necessary work requests with the MC/MP. They must also be required to advise the primary MC if they have chosen to use another MC/MP to perform the meter exchange, so that the MCs can coordinate the visit.

- Current obligations are unclear regarding which party is responsible for advising the customer of a temporary interruption. Interruptions involving the DNSP are, in our view, defined as a *Distributor planned interruption* and therefore it is the DNSP that is (currently) responsible for notifying affected customers. We believe that retailers should take on this responsibility in circumstances where the interruption is related to a meter exchange for the one-in-all-in scenario.

- The primary MCs must be able to use NMI Discovery in MSATS to determine who the retailers are for NMIs at a multi-occupancy site. This is so they can efficiently manage the raising of a work request (Service Order) and the coordination requirements in relation to each retailer. Current AEMO procedures prohibit MCs from accessing this information.

37. We agree with the timeframes proposed in the Draft Report for the one-in-all-in approach.

38. Regarding how the DNSP can recover the cost for the temporary isolation, we are of the view that this should be allocated across the retailers who are responsible for the NMIs that are impacted by the one-in-all-in meter exchange. Otherwise, retailers would not be incentivised to address multi-occupancy sites. An arrangement where cost recovery remains with the retailer who raised the service request for the temporary isolation will encourage retailers to defer visiting shared fused sites. We **recommend** that DNSPs be required to split this charge between retailers, or alternately recover these charges in their regulated network tariffs (DUOS). While this approach could be viewed as socialising the costs amongst all network customers, this could be seen as appropriate as these charges relate to circumstances that networks previously allowed to occur.

QUESTION 10: STRENGTHENING INFORMATION PROVISION TO CUSTOMERS

1. Do you have any feedback on the minimum content requirements of the information notices that are to be provided by Retailers to customers prior to a meter deployment?

2. Are there any unintended consequences which may arise from such an approach?

3. Which party is best positioned to develop and maintain the smart energy website?

39. Vector supports the proposal to reduce of the number of notices provided by the retailer to the customer in *new meter deployments* from two to one.

40. In relation to the recommendation for enhancing information to customers, we do not believe regulation is likely to result in more engaged customers. In fact, we see an increased risk of this driving higher complaints and refusals and activating campaigns by parties who are opposed to the deployment of smart meter technology, as was seen during the Victorian rollout.

41. We note the proposal outlined in table C.2 of the Draft Report that clause 59C of the *National Energy Retail Rules* (NERR) be amended to require the retailer to provide an additional notice containing the enhanced information requirements, and that this is to be provided no less

than 10 business days prior to the meter exchange. This clause currently allows the retailer to vary the timing and planned interruption notification requirements by securing explicit informed consent from the customer to an agreed date. Under these provisions, the minimum notice period (no less than four business days) is waived and the notice of interruption is not required. Any proposal that requires the enhanced information to be provided must not become a prerequisite for the meter exchange to proceed as this will create a barrier for meeting the customer's expectation. MPs and customers routinely use this consent to prioritise meter exchanges and allow them to occur without waiting for the regulated timeframes. We **recommend** that any additional information requirements should be designed separately from the current planned interruption notice provisions by allowing the enhanced information to be provided before, at the time of, or after the exchange, e.g. within 10 business days.

42. We note that the Draft Report proposes that the enhanced information obligations should apply to *new connections* as well as other customer-requested exchanges and the accelerated rollout (table C.1). However, the proposed changes outlined in table C.2 indicate that this information would not apply to new connections. We seek clarification regarding this proposal. In our view, new connections should be exempt from this requirement because:

    - The opportunity to issue the required information before the meter is installed is limited for new connections due to the tight timing requirements – six business days from the request date.
    - New connections are almost always arranged by a builder and we believe the information is unlikely to reach the end customer.

QUESTION 11: SUPPORTING METERING UPGRADES ON CUSTOMER REQUEST

1. *Do stakeholders support the proposed approach to enabling customers to receive smart meter upgrades on request?*

43. Vector agrees with the AEMC's proposed approach to enabling customers to receive smart meter upgrades on request.

Malfunctioning meter exemption process

44. We agree that 'individually identified malfunctions' and 'malfunctions identified through statistical testing' (i.e. family failures) should be treated separately under the rules.

45. We agree that the current exemption process for meters that are 'individually identified malfunctions' should be removed. In our view, this provides little value and ties up valuable resources for both MCs/MPs and AEMO.

46. However, we strongly believe that the current process for dealing with family failures is appropriate and should be retained. This process allows replacement timeframes to be varied based on the circumstances that are relevant, and potentially unique, to the family of meters subject to the failure – an approach we consider to be sound. At the very least, any mandated timeframe for replacement of family failures must consider the size of the meter family to be replaced. Expecting 150,000 family failed meters to be replaced in 70 business days, in addition to all other metering work, is unreasonable. We note that meters belonging to a family that has failed statistical sample testing are not all malfunctioning but have simply been identified as more likely to start operating outside the accuracy requirements sometime in the future. Having flexibility on the timeframe for replacing these meters that the exemption process offers does not impact the customer or threaten the market – and therefore remains appropriate.

QUESTION 12: TARIFF ASSIGNMENT POLICY UNDER AN ACCELERATED SMART METER DEPLOYMENT

1. *Which of the following options best promotes the NEO:*

   a. *Option 1: Strengthen the customer impact principles to explicitly identify this risk to customers.*
   b. *Option 2: Prescribe a transitional arrangement so customers have more time before they are assigned to a cost-reflective network tariff.*
   c. *No change: Maintain the current framework and allow the AER to apply its discretion based on the circumstances at the time.*

2. *Under options 1 or 2, should the tariff assignment policy apply to:*

   a. *all meter exchanges – for example, should the policy distinguish between customers with and without CER?*
   b. *the network and/or the retail tariffs?*

3. *What other complementary measures (in addition to those discussed above) could be applied to strengthen the current framework?*

47. Vector supports the *Option 2 prescribed transitional arrangements* above, which will help avoid problems related to tariff changes by disassociating the smart meter exchange from the network tariff change. We **recommend** that the practice of mandatory reassignment of a network tariff to a cost-reflective tariff be delayed for a period after the smart meter has been installed. This would allow a reasonable amount of historic data to become available, which could inform both the retailer and customer of the impact that a tariff change will bring.

48. Transitional arrangements that delay mandatory cost reflective (TOU & demand based) tariff changes (*Option 2 transitional arrangements*) should apply to all smart meter deployments except for new connections which do not cause 'bill shock' to customers. These arrangements should apply to network tariffs only and not to retail tariffs as competition between retailers will provide customers the ability to choose a retail product that best suits their needs.

QUESTION 13: MINIMUM CONTENTS REQUIREMENT FOR THE 'BASIC' PQD SERVICE

1. *Should the 'basic' PQD service deliver any other variables beside voltage, current, and phase angle?*

2. *Does the 'basic' PQD service require any further standardisation, e.g., service level agreements? If so, where should these service levels sit?*

3. *Should the Commission pursue a data convention to raise the veracity of 'basic' PQD?*

49. Vector supports the work already completed by the Review Sub-Groups in defining the Basic PQD service that all MPs will be obligated to provide and all DNSPs will be obligated to take. We agree that the variables identified (instantaneous voltage, current, and phase angle) meet the requirements of the basic service and that any other variables should be negotiated under 'more advanced' services. We note that section D.1 on page 10 of the Draft Report proposes changes to Chapter 10 of the NER to define PQD to include 'power factor' rather than 'phase angle', as was agreed in the Sub-Working Group. We assume this is a drafting error.

50. We believe that further standardisation of the basic service in the regulations beyond that proposed in the Draft Report is unnecessary given the AEMC's proposal that provision of this service is to be supported by a commercial agreement between the provider and the recipient (DNSP). Any SLAs and/or further standardisation can therefore be included in

these commercial agreements. We are of the view that further work is required by the DNSPs and MPs to develop a specification for message formats that can be referenced by participants in the commercial agreements. We **recommend** that this work commence as soon as possible in 2023.

51. We note that the Draft Report proposes that obligations to provide the basic PQD service and support commercial agreements should be imposed on the MC. In our view, these obligations should instead be imposed on the MP. This is because:

- The MP is the party who provides the platform to meet the requirements of the basic PQD service (and any advanced services that may be negotiated).

- The MC is a third party who may be unrelated to the MP, and in these cases, will sit between the MP and the recipient of the service (the DNSP in this case). This would require more complex commercial arrangements (back-to-back contracts) without providing any additional benefit and may introduce additional cost.

- As the retailer and MC roles routinely change with customer churn (while the MP roles generally remain constant), NMIs subject to the commercial arrangements for the provision of the basic PQD service between the MC and the DNSP will be continually changing. This will be avoided where the commercial agreement is between the DNSP and the MP.

QUESTION 14: UTILISING THE RIGHT EXCHANGE ARCHITECTURE FOR THE 'BASIC' PQD SERVICE

1. *Should the industry use the shared market protocol? If not, why?*
2. *Should stakeholders exchange PQD directly, using NER clause 7.17.1(f)?*
3. *If so, should the Commission prescribe this in the rules, or could this be by agreement between parties?*

52. Vector supports the standardisation of data exchanges between participants as this can lead to the most efficient mechanisms for the provision of PQD. However, before the shared market protocol (SMP) can be mandated as the default mechanism for industry for PQD exchange, we **recommend** that the AEMC confirm with DNSPs whether standardisation of format and delivery is what they require. Recent dealings with DNSPs in the Review Sub-Group, and in direct discussions with them regarding the delivery of this service, indicated that DNSPs would prefer to maintain flexibility on the method and form that PQD is transacted. Some believe that the use of the SMP is unnecessary and provides little additional value, especially if participants are not transacting via AEMO infrastructure (B2B e-HUB). Others are of the view that the SMP provides a mature set of established patterns that can be leveraged to form the basis for the PQD exchange.

53. We acknowledge that significant investment has already been made by the industry in defining the above patterns. The industry has built the infrastructure required to support a robust mechanism to exchange data using SMP (via Webservices API) and expects this to become the standard method of data exchange for the formal B2B transactions (Meter Data and Service Order Requests) once the legacy FTP mechanisms are retired (date yet to be set by AEMO). Under the NER, commercial parties are permitted to enter into agreements that determine the provision of a commercial service, and given the current indications from DNSPs that they prefer delivery via methods other than the SMP (Webservices API), then it is our view that mandating a default arrangement may be redundant. Note: If DNSPs cannot agree on a uniform approach for transacting PQD, then MPs will be required to support multiple methods which will attract additional costs that will be reflected in the price of the service. We encourage the AEMC to determine if DNSPs still support this level of

standardisation, and if they do not, then no rule should be made. If standardisation is preferred, then DNSPs and MPs still need to come together to determine which standards (existing or new) are required to enable the PQD to be exchanged.

54. We agree with the proposal that participants should exchange PQD data directly, rather than via the B2B e-hub. As discussed above, given the proposal by the AEMC that provision of this service will be supported by commercial agreement(s) between the MP and the recipient (DNSP), the technical details related to the method of data exchange can be included in these commercial agreements. Further prescription in the rules is therefore not warranted.

QUESTION 15: PRICES FOR POWER QUALITY DATA SERVICES

1. *Is it sufficient for the prices for PQD services to be determined under a beneficiary pays model, especially with a critical mass of smart meters?*
2. *Are alternative pricing models, e.g., principles-based or prescribing zero-cost access, more likely to contribute to the long-term interest of consumers?*

55. Vector agrees that the pricing of the basic PQD service should be based on a beneficiary pays model. Assuming the commercial arrangements are made directly between the MP and the recipient (DNSP), we are confident that this will result in prices that are limited to reflecting the marginal cost of providing the service, including a reasonable level of return for the MP.

56. Should the AEMC determine that the barriers to direct negotiation between the parties are insurmountable, then we would support the AER determining a fair and reasonable price for the service, based on information on costs provided by MPs, and that this price is to be paid by the DNSPs to the retailers to be passed on as part of the annual meter charges. This approach may provide a remedy to the perception that direct negotiation between DNSPs and MPs will not deliver efficient costs and would remove the need for DNSPs to negotiate a service provision from each metering service provider.

57. Further to this, we refer the AEMC to Vector's response to the *Review of the Regulatory Framework for Metering Services – Directions Paper* (paragraph 33)[4] where we proposed the implementation of a temporary tariff discount provided by networks to retailers that gradually decreases, for sites that had smart meters installed, paid for by all customers. This approach has many advantages and would be revenue neutral to the DNSP and could include the price of the PQD service.

58. We note that some commercial arrangements established between retailers and their MC, or between the MC and the MP, have restricted the provision of PQD to third parties including DNSPs. We **recommend** that this issue be dealt with under the regulatory framework for the beneficiary pays model to be successful. We expect a regulation that requires MPs to provide this service, on commercial terms, to parties who are entitled to receive it, will resolve this issue.

59. The Draft Report discusses access to a PQD service for parties other than the DNSP and is seeking feedback on this matter. While we support the delivery of data services to a broader constituency, where that party is not a market participant with a formally recognised financial interest in the site, challenges related to customer privacy and authorisation arise. Unless third party access is authorised by legislation, access must be authorised by the customer, which is difficult for MCs or MPs to verify as they do not maintain customer details. Any authorisation will need to be referred to the retailer for confirmation, as is required under the Consumer Data Right (CDR) model. It is also difficult to see a valid use case for small

[4] https://www.aemc.gov.au/sites/default/files/2021-11/Rule%20Change%20Submission%20-%20EMO0040%20-%20Vector%20-%2020211028.PDF, paragraphs 31-32 and 61

customers to be specifically interested in technical PQD as a high level of technical knowledge is required to interpret this data.

60. At this point, we believe that any demand for a PQD service for third parties (i.e. other than the DNSP) will remain low. This is supported by our experience across multiple jurisdictions (in the NEM and in New Zealand) where we have received almost no requests over the many years that this data is available. Should third parties require access to this service, it is probable that it will attract additional costs as the delivery mechanisms and bespoke requirements to manage ongoing access will drive new processes into MP businesses. Due to the uncertainty in the demand for a PQD service for third parties, we **recommend** that no action in the regulatory framework is necessary at this stage of market development.

QUESTION 16: REGULATORY MEASURES TO ENABLE INNOVATION IN REMOTE ACCESS TO NEAR-REAL-TIME DATA SOONER

1. *Do stakeholders support the Commission pursuing enabling regulatory measures for remote access to near real-time data? If so, would it be suitable to:*

    a. *Option 1: require retailers to provide near real-time data accessible by the consumer in specific use cases (while allowing them to opt-out).*
    b. *Option 2: allow customers to opt-in to a near real-time service via their retailer for any reason.*
    c. *Option 3: promote cooperation and partnerships between Retailers and new entrants for near real-time data services, e.g., in a regulatory sandbox.*

2. *If so, could the Commission adapt the current metering data provision procedures?*

3. *Are there any standards the Commission would need to consider for remote access? E.g., IEEE2030.5, CSIP-AUS, SunSpec Modbus, or other standards that enable 'bring your own device' access?*

4. *What are the new and specific costs that would arise from these options and are they likely to be material?*

61. The technical ability to support remote access to "near-real-time" customer consumption data has already been enabled in the marketplace (for example, under the CDR). We are witnessing the emergence of these services being offered by retailers to their customers.

62. We do not necessarily agree that mandating retailers to provide new services using near-real-time data will elicit a level of engagement from customers more than emergent reforms – such as demand-side flexibility or dynamic operating envelopes – can.

63. We view regulation in this space to be a risky endeavour and is akin to a 'build it and they will come approach' or 'gold plating' a service. The AEMC only needs to look as far as the Victorian AMI program where near-real-time access to data from the meter has been available for many years via direct connection to the meter over the Zigbee protocol, and via retailer and network portals that provide up-to-date consumption data to the most recent reading interval. We are not aware of evidence that a significant number of Victorian consumers, or their retailers, are taking advantage of these capabilities.

QUESTION 17: REGULATORY MEASURES TO ENABLE INNOVATION IN LOCAL ACCESS TO NEAR-REAL-TIME DATA SOONER

1. *Do stakeholders support the Commission considering regulatory measures for local access to near real-time data? If so, would it be suitable to:*

> a. *Define a customer's right in accessing the smart meter locally for specific purposes?*
>
> b. *Outline a minimum local access specification, including read-only formatting and uni-directional communications? Are there existing standards that MCs can utilise, for example, IEEE2030.5, CSIP-AUS, or SunSpec Modbus?*
>
> c. *Codify a process for activating, deactivating, and consenting to a local real-time stream? If so, could the Commission adapt the current metering data provision procedures*
>
> 2. *Are there any other material barriers that the Commission should be aware of?*

64. While Vector acknowledges the intent of proposing regulatory measures to enable local access to near-real-time data, it is our view that it is premature to alter the regulatory framework to mandate the provision of this service for the following reasons:

- <u>Lack of clarity on the use cases that this requirement is to support</u> - The scenario where near-real time usage information is provided directly to the customer from the meter does not appear to be supported by experience in other jurisdictions. The ability for the customer to receive this type of data has been available since the introduction of smart meters (regardless of whether it is via direct local access or via cloud service as described in the Draft Report) but we have seen little interest from customers for this type of service.

  In Victoria, support for direct integration with the meter via ZigBee was made mandatory in all meters deployed under the AMI rollout, yet there is very low take-up of this feature by customers. In New Zealand, there is also little interest from our customers in receiving immediate real-time data. We therefore question whether this use case should be the driver for a material change to the meter specifications.

  The Clean Energy Council's (CEC) request for the AEMC to include local access appears to be related to their preference to integrate customer energy resources (CER) equipment with the smart meter to avoid the need to install dedicated measurement devices required to meet existing and emerging obligations, e.g. dynamic operating envelopes, flexible export limits, etc. We recognise that this may be a desirable outcome but believe there are technical barriers that will need to be overcome before this can be realised (discussed further in the next point). We note that the CER industry recognises these technical barriers and have been addressing these with their own solutions for some time that optimise customer outcomes for a specific CER investment. We believe this will continue to be the approach preferred by CER providers (as confirmed by informal discussions with CER industry participants), rather than relying on the smart meter which may have limited technical functionality and is provided and managed by a third party.

- <u>Standards or lack thereof</u> - To connect CER devices to the smart meter, appropriate standards must be established. Our understanding is that the CER industry remains divided on whether the functions of the smart meter and the existing protocols (e.g. Sunspec Modbus) can meet the requirements to allow for the effective management of CER devices in the low-voltage (LV) network. One view from the CER industry is that effective control requires a continuous stream of measurement data to be provided to the CER command and control system so that CER devices can ramp generation output up and down as LV conditions change. This is currently achievable using an analogue feed which is not supported by the proposed protocols (to our knowledge), and new standards are therefore likely to be required. CER service providers currently meet these requirements by installing their own measurement devices which are tailored to their requirements and provide the constant stream of data in a format that is compatible with their CER devices.

Should the AEMC require that existing standards be supported, it is likely that these will be found wanting in a number of important scenarios and the CER industry will still need to install specialist devices to meet their obligations. To our knowledge, there has been little engagement between the CER industry and the metering industry to discuss these issues and find solutions. It is therefore our view that more work is required by the CER industry, metering service providers, and metering manufacturers to fully understand the objectives of the CEC and the CER industry before any change to the minimum metering specification can be made.

- Economics – It is unclear if the AEMC proposes to perform a cost-benefit analysis on changes to the minimum metering specification to support the addition of standardised local access. The Draft Report states that local access '..presents significant potential benefits' (page 119) and that '[c]onsumers would realise a material benefit by integrating the real-time stream with CER' (page 120) without providing any quantifiable evidence. Should the AEMC require smart meters to provide a method for local access, meter manufacturers will be required to re-engineer their equipment to add this functionality. Depending on the requirements, this may result in a need for additional memory, higher-grade CPUs, and external ports to be made available. Depending on the nature of the changes, this will inevitably increase the cost of the meter which will be borne by all customers. If the core use case for local access is to integrate smart meters with CER devices, as suggested by the CEC, then customers who benefit from this integration should pay for the fit-for-purpose devices. We believe this is more cost-effective overall than pushing the cost of these features into all smart meters which will be borne by all customers regardless of whether they are taking advantage of the available features or not.

- Authorisation and control – The Draft Report suggests that there may be a requirement for new processes to enable ports on a meter to allow external devices to be connected. Allowing external devices to connect to the meter via a physical port raises obvious issues related to the devices that are connected. Once access has been provided and the port is active, control by the MP is effectively lost. Unless complex processes are established, e.g. security certificate exchanges etc, MPs are unable to determine what the device is on the end of the connection and whether it should or should not have access. Complexities arise on how often an enabled port should be checked to see if access is still required (e.g. annually) and how MPs could effectively do this, especially when the customer has churned away from the retailer who organised the port activation and the new retailer is unaware of the situation. Once the port is enabled, we foresee that it would never be disabled.

  Should the AEMC require access to the meter via a physical port, then we **recommend** that to avoid these complex access processes, the port should always be enabled. It must be recognised that apart from taking necessary steps to protect the meter from nefarious attack via the port, the MP cannot be held responsible for the devices that are connected to this port or where the customer has authorised or revoked authorisation of its use.

65. We agree with the AEMC's findings that any change in the minimum meter specification will result in meters already deployed not being able to meet the requirements. Any material changes, such as making an external Ethernet port available, will require a lead time and it is therefore likely that the majority of customers will already have received a smart meter under the accelerated rollout without the ability to support local access. Presumably, these meters would be exempt from meeting any new requirements. It is unclear what the regulatory framework proposes to do with these smart meters should the customer request local access or CER devices are installed after the smart meter installation. It appears wasteful to require the MP to attend the site with an already installed functioning smart meter and replace it just to enable local access to allow a CER device to connect. This is something we would not support.

66. We also have concerns about non-qualified people plugging devices directly into the meter. Making a port available invites the customer to plug a cable into the meter and exposes them to potential safety issues. MP field resources are trained to treat every meter installation as a hazardous situation and to wear appropriate personal protective equipment when approaching the meter. Creating an environment where untrained people are interacting with a meter is something that should be avoided.

67. For the reasons stated above, we do not support regulation for local access services at this point in time.

Concluding comments

68. We are happy to discuss any questions the AEMC may have on any aspects of this submission. Please contact Paul Greenwood (Industry Development Australia, Vector Metering) at Paul.Greenwood@vectormetering.com or 0404 046 613 in the first instance.

69. No part of this submission is confidential, and we are happy for the AEMC to publish it in its entirety.

Yours sincerely

Neil Williams
Chief Operating Officer
Metering and OnGas