SA Power Networks

Mitchell Grande
Australian Energy Market Commission
Submission made online at www.aemc.gov.au

2 February 2023

Dear Mitchell,

Subject: EMO0040 AEMC draft report: review of the regulatory framework for metering services

SA Power Networks welcomes the opportunity to provide feedback in response to the above draft report.

The transition to smart meters is a key step in the evolution of the NEM to support a low-carbon future and the continued integration of Customer Energy Resources (CER) with the grid. We welcome the AEMC's review of the current metering arrangements and commend the AEMC on its constructive approach to stakeholder consultation through the course of the review.

It has become increasingly clear since the introduction of competition in metering that the current regulatory framework has serious flaws that have led to unnecessary costs, a failure to realise potential value, and poor customer outcomes. The AEMC's review is, perhaps, the final opportunity to correct these flaws and enable the realisation of the customer benefits originally intended. We strongly urge the AEMC not to shy away from recommending significant regulatory changes where these are necessary to address the root cause of issues and are in customers' interest. If the review only delivers 'band aid' solutions that add to the complexity of the current framework and don't address the underlying problems then the significant efforts of the AEMC and all stakeholders through the review process will have been wasted, the opportunity will be lost, and customers will continue to be disadvantaged.

Our high-level feedback on the AEMC's draft report and preliminary recommendations is summarised below, and we have included detailed responses to the consultation questions in Attachment 1.

A pathway to 100% uptake

1. We support accelerating the rollout with a target of 2030 for completion.
2. Of the options put forward, we consider that option 1 ('legacy meter retirement plan') will provide the best outcome.
3. For option 1 to work it will be important that a clear timeframe is set for the development of the plan that allows for adequate consultation with all stakeholders, but also sets a clear end point for plan approval so that the rollout can commence in time to achieve the 2030 target. To complete the process in a timely manner the DNSP would need to have the authority to make decisions where consensus can't be reached on any aspect of the plan, with the AER approval process as the final check.

4. It will also be necessary to define the rules around execution of the plan, including the governance framework and how parties are to be held accountable under the rules for delivering on their aspects of the approved plan.
5. Any rule change would need to include clear provisions for the DNSP to recover its efficient costs to perform the planning and coordination functions, independent of the timing of their regulatory determination cycles.
6. While option 1 is the best of those put forward, none of the AEMC's proposed approaches will fully resolve the difficulties in achieving a coordinated rollout within a framework in which the retailer retains responsibility for activating each meter replacement. There may be alternative models, e.g. where the DNSP works more directly with the MCs on the execution of the plan, that would give better outcomes, and this warrants further consideration.

Enhancing existing metering arrangements

7. While we offer some specific feedback on certain aspects in Attachment 1, we generally support, in principle, the AEMC's proposed measures to improve existing processes, namely:
   - Customers should be entitled to receive a smart meter if they request one
   - Reduction from two to one notice required when retailer initiates a meter change
   - Removal of opt-out (other than in specific circumstances)
   - Improvements to process around meter failures
   - A 'one in, all in' approach to multi-occupancy premises

8. We have provided feedback on the AEMC's proposed process for multi-occupancy premises in the attachment, but in summary:
   - There would need to be a clear guideline for MCs to follow if they are the first to attend a site to ensure that the site is properly scoped during the first visit and the MC can confirm that replacement of all meters will be possible with no site remediation. The worst outcome will be to isolate supply but then discover on the day that it's not possible for all MCs to complete their replacements and a second round of work is required.
   - The proposed 20 business day timeframe for the DNSP to assess the site, agree a date for the replacement with all affected customers and issue MFNs is a reasonable target, but should be on a 'best endeavours' basis. For complex sites with multiple customers with different needs, especially business customers, more time may be needed to negotiate and agree a date that minimises cost and inconvenience for all. Similarly, there would need to be some flexibility in the proposed 45 business day timeframe for the installation, for cases where affected customers may prefer a longer timeframe or could even prefer that the work was split over several stages rather than incur one long outage.
   - We foresee many issues of failed jobs and extended or repeated customer outages arising from the need to coordinate multiple parties under the proposed process. The only way to deal effectively with multi-occupancy sites would be to have a single party undertake all replacements, and we do not expect this would occur under the AEMC's proposed method. If there is an alternative approach that would enable this we would expect it to result in lower costs, less complexity and better customer outcomes. Perhaps the DNSP, being independent of the retailers, could play a more direct role, either as deemed MP for multi-occupancy sites (performing meter installation works for all MCs) as we have suggested previously, or in nominating a

single MC for each site through a process agreed as part of the plan and approved by the AER.

Supporting customers through the transition

9. We support the AEMC's proposal to provide a primary-source website and other information to customers to improve understanding of the process, including addressing customer data privacy concerns. We consider that the Commonwealth Government would be best placed to develop this site given that this is a national initiative and given that it already provides independent, trusted online resources for NEM customers like Energy Made Easy.
10. Ideally, the site would include information on the proposed rollout schedule in each jurisdiction (similar to the NBN rollout), so that customers would have some indication as to the likely timeframe for meter replacements in their area.
11. We consider that the current rules framework for tariff assignment is adequate and we would not support introducing a mandatory delay of 12-18 months between when a customer receives a new meter and when they could be assigned to a cost-reflective network tariff. DNSPs should continue to follow the tariff transition pathways developed and agreed with their customers through the TSS process. Moving to better tariffs is the key reason we embarked on the transition to smart meters in the first place. While we recognise some stakeholders' concerns around tariff reassignment, we believe that TOU tariffs are in all customers' long-term interest, in particular those customers who do not have access to rooftop solar or other CER. Better tariffs will help lower prices for all and reduce inequity over time, so we would not want to see the progress that is already occurring on tariff reform unduly impeded.
12. If there is a strong desire to decouple meter replacement from tariff reassignment for customers post-2025 then any provisions should focus on the retail tariff assignment process and not delay the transition of the network tariff. One approach could be a default reassignment with a provision for opting out to a different retail tariff within a defined timeframe.

    Our views on tariff transition are further elaborated in Attachment 2.

Unlocking new customer benefits

13. Besides tariff reform, most of the other consumer benefits from smart meters arise from the improved network visibility they provide to the DNSP. Almost none of these benefits are being realised in the NEM outside Victoria today even though there is now a significant population of installed meters – being paid for by all customers – that are designed to provide this data, because they are not activated to do so.
14. We are extremely concerned and disappointed that the AEMC's draft report fails to address the root cause of this issue: the assumption in the rules that DNSPs should enter into commercial contracts with metering coordinators and pay for access to this data, with no regulatory support for price setting. This cannot work for 'basic power quality data' that is, by definition, required for every meter, because each metering coordinator has an effective monopoly over the provision of the data from the meters it controls. The DNSP can't choose the MC, they must take whatever service is offered by the MC the retailer has appointed, and

so the DNSP has no basis on which to negotiate a commercial arrangement – they are simply a price-taker in the relationship. As any payments made by DNSPs for metering data are passed directly to customers, it is the customer, not the DNSP, who will suffer higher costs if the DNSP has no power to negotiate a reasonable price.

15. The provision of power quality data to the DNSP is technically straightforward and is one of the basic functions that makes a smart meter a smart meter. Providing this data should simply be a requirement of the standard metering service, and any associated marginal cost should be included in the annuity paid by the retailer to the MC. In this case the cost to customers is restrained by competition between MCs and there is no need for additional contracts or unnecessary administrative costs. Such an arrangement also provides the certainty of ongoing access and cost that DNSPs require for their regulatory proposals, and provides the MC certainty of future cost recovery for any marginal cost of providing the data.

Alternative approaches

While we have limited ourselves in this letter to commenting on the proposed changes canvased in the AEMC's draft report, we urge the AEMC to remain open to alternative approaches where these could achieve better customer outcomes. For example, we understand that some customer advocates have proposed changing the rules so that the DNSP, not the retailer, would become responsible for appointing the MC for future meter replacements and paying for the entire metering service. On the face of it, this would seem to offer an elegant way to achieve an efficient and well-coordinated rollout and resolve the root cause of key issues with the current framework like multi-occupancy premises and access to network data by DNSPs, while preserving the fundamental elements of competition in metering and the MC role. We think this idea warrants further consideration.

We look forward to continuing to engage constructively with the AEMC and other stakeholders to support efforts to address deficiencies in the NEM metering framework. In the meantime, if the AEMC has any questions on any aspect of our response, please contact Bryn Williams, Network Strategy Manager, at bryn.williams@sapowernetworks.com.au.

Mark Vincent
General Manager Strategy and Transformation

Attachment 1: responses to consultation questions

QUESTION 1: IMPLEMENTATION OF THE ACCELERATION TARGET

1. Do stakeholders consider an acceleration target of universal uptake by 2030 to be appropriate?

Yes.

2. Should there be an interim target(s) to reach the completion target date?
3. What acceleration and/or interim target(s) are appropriate?

Under the AEMC's proposed approach, the rollout plan would be developed in consultation with stakeholders, would include annual targets for replacement through the 2025-2030 period, and would be subject to approval by the AER. With this approach, prescribing interim targets in the rules would not seem to be necessary.

4. Should the acceleration target be set under the national or jurisdictional frameworks?

A target should be set in the national rules as part of the overall package of rule changes arising from this review. This will avoid further delays, give certainty of intent and promote national consistency – noting that any individual jurisdiction that wanted to set a different target could still derogate from the one set in the Rules.

QUESTION 2: LEGACY METER RETIREMENT PLAN (OPTION 1)

1. Do stakeholders consider this approach feasible and appropriate for accelerating the deployment of smart meters?

Of the options put forward, we think option 1 will give the best outcome, for reasons set out in our response to Question 5 below.

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?

The principles set out in box 4 (pp 42-43 of the draft report) seem reasonable.

3. If this option is adopted, what level of detail should be included in the regulatory framework to guide its implementation?

As far as possible, the regulatory framework should be principles-based, not prescriptive, to allow each DNSP to develop a process tailored to its own jurisdiction, service area and stakeholders. That said, the framework should be definitive in certain aspects:

- It will be important for the regulatory framework to set clear bounds on the timeframe for completion of the consultation, plan development and AER approval process. A drawn-out or open-ended process involving multiple rounds of consultation and review will only further delay the rollout and will not be in customers' interest.
- Stakeholders will have competing objectives and priorities and so no plan will fully satisfy all parties. It will be important, therefore, that the framework gives clear authority to the DNSP

to weigh competing priorities and make decisions in cases where stakeholders disagree. So long as the DNSP demonstrates that it has engaged adequately and transparently with all stakeholders in the development of the plan and, where stakeholders disagree, appropriately applied the agreed principles in making decisions that best promote the NEO, the plan should be capable of acceptance by the AER.

4. Do stakeholders consider a 12-month time frame to replace retired meters appropriate? Should it be longer or shorter?

To achieve the goal of completing the rollout by 2030 it should not be longer than 12 months and would ideally be shorter.

The draft report states (p 43): "*To take into consideration customer churn, the time frame obligation on the retailer would commence from the time it acquires a customer with a retired legacy meter*". One issue with this approach is that a customer who changes retailer regularly could delay their meter replacement indefinitely. It will also impact on efficiencies built into the plan if a small number of meters scheduled to be replaced as a batch (e.g. to complete a geographic area) are delayed by 12 months or more due to retail churn. While some delays may be unavoidable if a customer churns retailer close to the date their meter is scheduled for replacement, as far as possible the intended replacement date should be preserved even though the customer has changed retailer. In practice it will be the MC who will need to do the detailed scheduling of meter replacements in any event.

5. Are there aspects of this approach that need further consideration, and should any changes be made to make it more effective?

The proposed approach effectively transfers some of the work and responsibilities that were originally intended to be borne by retailers back to DNSPs. It will drive new costs for each DNSP in planning and coordinating the rollout that would not have been allowed for in its regulatory revenue allowances that need to be recovered. Any rule change would need to include clear provisions for the DNSP to recover its efficient costs, which may be material (and likely more than the estimates in the Oakley Greenwood Cost-Benefit analysis) but will not meet the threshold requirements for a cost passthrough as a regulatory change event per NER 6.6. One way would be to waive the passthrough threshold for cost recovery for activities associated with the accelerated meter rollout.

As well as the planning phase, the AEMC also needs to consider how the rollout will be governed once the plan is underway. There would need to be an overarching governance group to oversee and manage the rollout, provide for escalation and issues resolution, and so on. There would need to be a clear mechanism to hold each party accountable for performance against the agreed plan, noting that if one party diverges from the plan it will impact on, and drive costs for, other parties. Consideration should be given to the role of the AER in ensuring compliance to the plan, the obligations on parties with respect to tracking and reporting progress against the plan, and whether penalties should apply for non-performance.

QUESTION 3: LEGACY METER RETIREMENT THROUGH RULES OR GUIDELINES (OPTION 2)
QUESTION 4: RETAILER TARGET (OPTION 3)

Of the options presented, we agree with the AEMC that option 1 would give the best outcome for the reasons set out in the draft report and in our answer to question 5 below, so we have no further comments on options 2 and 3.

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

1. What is the preferred mechanism to accelerate smart meter deployment?

Of the options presented, we agree with the AEMC that option 1 would give the best outcome.

A plan led by DNSPs with input from other stakeholders offers the best opportunity to accelerate customer benefits by staging and prioritising replacements, for example to:

- Enable the efficient retirement of manual meter reading routes by completing whole geographic areas at a time
- Coordinate the replacement of meters at multi-occupancy premises
- Prioritise cohorts such as customers at higher risk of a degraded neutral connection to their premises, to maximise safety benefits (as smart meter data can detect faults to the customer's neutral connection that present an electric shock hazard in the home)
- Prioritise segments such as customers with traditional off-peak controlled load hot water, to facilitate shifting of these loads to the daytime 'solar sponge' period in high-solar jurisdictions like South Australia, saving customers money

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?

The above issue of customer churn highlights that none of the AEMC's proposed approaches will fully resolve the difficulties in achieving a coordinated rollout within a framework in which the retailer retains responsibility for activating each meter replacement and has flexibility around when these occur. Even within an agreed overall plan based on annual batches of meter replacements, retail churn and different retailers' preferences in when to schedule their replacements within each annual 12-month replacement cycle will likely lead to a messy and uncoordinated rollout where the hoped-for benefits like retiring manual meter reading routes are delayed.

Even with best efforts, DNSPs will be limited in their ability to coordinate multiple parties where they cannot fully manage the end-to-end process. There may be alternative models, e.g. where the DNSP works more directly with the MCs on the execution of the plan, that would give better outcomes.

For example, we understand that some customer advocates have proposed changing the rules so that the DNSP, not the retailer, would become responsible for appointing the MC for future meter replacements and paying for the entire metering service. On the face of it, this would seem to offer an elegant way to achieve an efficient and well-coordinated rollout and resolve the root cause of key issues with the current framework like multi-occupancy premises and access to network data by

DNSPs while preserving the fundamental elements of competition in metering and the MC role. We think this idea warrants further consideration.

QUESTION 6: FEEDBACK ON NO EXPLICIT OPT-OUT PROVISION
QUESTION 7: REMOVAL OF THE OPTION TO DISABLE REMOTE ACCESS

We support the AEMC's proposed approach to opt-out and disabling remote access.

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?

We agree that DNSPs should not be funding or undertaking customer site remediation. To the extent that some customers require assistance with site remediation this would be best addressed by governments. Beyond that, we do not have strong views on how best to manage this aspect of the rollout, but we urge the AEMC to be guided by:

- Current and historical practice for customers requiring site remediation as part of a meter replacement, noting that mandatory meter replacements arising from meter family failures have always existed so these issues are not new. An accelerated rollout simply increases the number of such replacements, and hence the number of associated site remediation issues, each year relative to historical rates.
- Lessons learned from the Victorian DNSPs, who have already negotiated these issues to achieve a near-100% rollout.
- The likely need for some provision for exemptions or delays in meter replacement where there are specific circumstances, e.g. if the necessary site remediation would cause genuine financial hardship to the customer.

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?

We support a one-in-all-in approach for multi-occupancy sites.

2. Are the time frames placed on each market participant appropriate for a successful installation process of smart meters?

The AEMC proposes 20 business days for the DNSP to (a) attend the site to identify all the NMIs, (b) determine an installation date and (c) issue MFNs. We consider 20 business days to be a reasonable target, but it may not always be achievable (or not without negative customer impact). Step (b), determining the installation date, may require considerable negotiation with the landlord and/or all customers, particularly for business customers, noting that the length of the outage is likely to be significant and it may be challenging to agree a day that minimises impact for all. A 20-business-day target would need to be set on a 'best endeavours' basis, or there would need to be some provision for variation where it is warranted.

Similarly, the AEMC's proposed target of 45 business days from issuing the MFNs to the scheduled installation date is reasonable for customer-initiated replacements, but for the accelerated rollout the process should allow for flexibility in this timeframe where this is in the interest of the affected customers. Customers at some sites may prefer a longer timeframe, or may even prefer to have the work undertaken in stages, with several shorter outages for meter replacement rather than one long one.

3. Are there any unforeseen circumstances or issues in the proposed installation process flow and time frames?

We do not expect that this process would result in the appointment of a single MC for a site, as this would involve retailers agreeing to appoint a non-preferred MC for their customers' meters. Without a single MC, we foresee many issues of failed jobs and extended or repeated customer outages arising from the difficulty in coordinating multiple parties under the proposed process. In our view the only way to fully resolve the issue of multi-occupancy premises will be to develop a process that requires a single party to install meters for the whole site.

Perhaps the DNSP, being independent of the retailers, could play a more direct role in nominating a single MC for each multi-occupancy site. This would ideally be through a transparent process agreed as part of the plan and approved by the AER, to ensure fair competition between qualified MCs for these sites. Alternatively, the DNSP could be the deemed MP for multi-occupancy sites, performing meter installation works for all MCs as well as site isolation and reconnection, as we have suggested previously.

Finally, we understand that the intention is that the proposed 'one-in, all-in' process would only apply to meter exchanges undertaken as part of the accelerated rollout, and not for customer-initiated meter replacements, which we think is reasonable. Any new rules would need to be clear on this point.

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?

We would need to revise our approach to pricing for the isolation once the details of the framework were confirmed. This could, for example, involve several standard price tiers for a multi-occupancy site depending on the number of meters (and hence the likely outage time and coordination effort involved), with the fee for the site allocated pro-rata to the retailers.

The process would need to consider who bears the additional cost if a second round of work needs to be scheduled, e.g. because an MC fails to turn up on the day, or doesn't complete their work on time, or finds they are unable to complete their work due to a site issue that only affects a subset of the meters, etc.

6. Which party should be responsible for sending the PIN in the context of the one-in-all-in approach?

In the proposed one-in-all-in approach it would make sense for the DNSP to send the PIN to the customer. The framework would need to make it clear that the retailer did not have any obligation to also send the customer a PIN in this case, to avoid duplication.

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 prior to customers prior to a meter deployment?

No comment.

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

In cases where the DNSP arranges the site isolation and sends the PIN to the customer (e.g. multi-occupancy premises or cases where the MC cannot safely isolate supply) the associated information notice sent by the retailer would need to precede the PIN, and not duplicate information in the PIN.

We agree that any information notice should include a reference to the web site and that the web site would be the primary source of information on the non-retailer-specific aspects of the rollout, to avoid duplication of effort and ensure clear and consistent messaging from an independent source.

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

We consider that the Commonwealth Government would be best placed given that this is a national initiative and given that it already provides independent, trusted online resources for NEM customers like Energy Made Easy.

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?

Yes.

Under an accelerated rollout plan, it may be beneficial to include some allowance for retailers to defer customer-initiated requests to the scheduled replacement date, in cases where the customer’s meter is already scheduled for replacement in the near future.

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.

Option c, 'no change'.

While we recognise some stakeholders' concerns around tariff reform, having considered the issues set out in the AEMC's draft report we consider that the current rules framework for tariff assignment is adequate.

We do not support option (a) because:

1. We consider the existing TSS process to be robust, transparent and effective in ensuring that customer impacts are taken into consideration in network tariff reform. Network tariffs and the tariff transition process are co-designed with customers through the TSS process to reflect the preferences of customers in each jurisdiction. In addition, the AER already has adequate powers through this process to intervene where it considers it necessary, as demonstrated by the AEMC's example of the additional transitional arrangements that the AER put in place for South Australia in response to the impacts of the COVID 19 pandemic.
2. As the TSS is part of the 5-year regulatory determination process for DNSPs, and DNSPs' regulatory periods will be mis-aligned to varying degrees with the proposed 5-year accelerated rollout period, changes to the TSS will not be effective in setting parameters for the proposed rollout.

We do not support option (b) - introducing a mandatory delay of 12-18 months between when a customer receives a new meter and when they could be assigned to a cost-reflective network tariff. Moving to better network tariffs is the key reason we embarked on the transition to smart meters in the first place. We believe, as set out in the original Power of Choice reforms, that cost-reflective tariffs are in all customers' long-term interest. This includes vulnerable customer cohorts, who tend to be most exposed to the price impacts of growing cross-subsidies under flat tariffs. The purpose of cost-reflective pricing is to lower prices for all and reduce inequity over time, so we would not want to see progress on tariff reform unduly impeded.

We have provided further detail on our rationale, including customer impact data from an analysis of our TOU tariffs in South Australia, in Attachment 2.

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?

We would see no basis for discrimination between CER and non-CER customers.

b. the network and/or the retail tariffs?

We do not support a mandatory delay in tariff re-assignment, for reasons set out above and in Attachment 2.

If such a delay were introduced, however, then our strong view is that this should be applied only in the case of involuntary (not customer-initiated) meter replacements, and only to retail tariff re-assignment, not the network tariff. One approach could be a default reassignment with a provision for opting out to a different retail tariff within a defined timeframe. In this case retailers would still be exposed to cost-reflective network pricing and could choose whether and how to reflect this in their retail offers for those customers seeking to opt out. Any such provisions would need to be limited to ensure that tariff re-assignment could not be delayed indefinitely, to maintain progress in the transition to better tariffs for all.

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

No comment.

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

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

No. We support the definition of the basic PQD service developed by the AEMC's working group.

We support the working group's recommendation that two other services should also be required to be provided as a minimum for every meter: the meter enquiry service, and a multi-meter ping service.

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

Yes. The service definition should include

- data delivery frequency - minimum daily, but preferably 6 hourly as recommended by the working group after considerable examination of this issue
- data to be delivered in an industry standard data format using an industry standard data delivery protocol. We support the format and protocol proposed by the working group (JSON, SMP, etc) and consider that these details are best captured in an operating procedure referenced in the rules rather than the rules themselves, as with other meter data provision procedures.

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

We would expect that the existing accuracy requirements and standards in place for the measurement of active and reactive power would also ensure the accuracy of basic PQD, but meter manufacturers will be best placed to advise on this.

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?

We note the preference of DNSPs and MCs in the working group was to exchange PQ data on a peer-to-peer basis and not rely on AEMO's B2B e-Hub. We consider the data exchange architecture is something best defined in an operating procedure referenced in the rules, rather than prescribed in the rules. A key consideration in a peer-to-peer delivery model will be establishing a common cyber security framework and the management of digital certificates to ensure secure exchange of data between authorised parties.

Governance arrangements for the data exchange standards would need to be defined, with a suitable, lightweight governance process overseen by a body that includes representatives of DNSPs, MCs and MDPs, as the parties involved in the exchange of PQD. This could be via a subset of the existing IEC, but we would not recommend adopting the full IEC process as the IEC includes a broader range of stakeholders and involves a level of governance and rigor that is unlikely to be necessary for basic PQD standards.

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?

No.

While we support the AEMC's recommendation that MCs should not be able to withhold – or be required through contracts with retailers to withhold – access to basic PQ data by DNSPs, we are extremely concerned and deeply disappointed that the AEMC's draft report focuses on the technical details of data delivery but fails to address the root cause of the data access issue.

The current access arrangement, where DNSPs must procure access to PQ data on a commercial basis from MCs, cannot work at scale. The framework establishes the MC as a monopoly provider of this data, and the DNSP as a price taker.

While the AEMC report refers to this arrangement as 'beneficiary pays' it is, of course, not the DNSP but the customer (who is already paying for their smart meter) who would pay the additional price of any data services procured by the DNSP, as all DNSP operating costs are passed directly through to customers in the NEM. If the DNSP cannot negotiate a fair price then customers will pay more.

The draft report acknowledges that the current framework is not working, but then proposes to retain the status quo – that 'price should be determined commercially', with no regulatory support or oversight of price-setting, even for the basic, universal data service that smart meters were always intended to provide, that underpins many of the intended customer benefits.

If this is the final outcome of the review, it will have failed. It will lead to ongoing data access issues for DNSPs, ongoing delays in benefits realisation, and higher prices for electricity customers in the long term.

We provide further comment in relation to current data contracts in box 1 below.

Box 1. A note on current data contracts

We recognise that the AEMC may be encouraged by the fact that most (or perhaps all) DNSPs already have contracts to procure PQ data from MCs on a trial basis.

Where SA Power Networks procures data from MCs for our own trials today, the data specification and price were negotiated individually with each MC following an EOI process. In this case we were seeking to procure data for a small number of meters only, and had flexibility in terms of the sample set, which meant that we had a choice of MCs and we were able to follow the normal process of tender, supplier selection and commercial negotiation.

This is quite different to the long-term outcome intended of the meter rollout, which is to enable ubiquitous access to basic PQ data from all meters for DNSPs – noting that this ubiquity is fundamental to key customer benefits like neutral fault detection. In the case where the DNSP requires the same data set from all meters a competitive tender process is impossible because each MC holds a monopoly over provision of data from its portion of the meter fleet.

We enjoy good relationships with the MCs we currently procure data from, and the data has been invaluable in supporting small-scale, localised trials of advanced voltage control, flexible export limiting and neutral fault detection, as well as improving our understanding of the performance of our Low Voltage network.

Our current contracts are, however, limited in scope to enable technology trials only, and do not provide a basis for high meter volumes, long-term access or the level of future price certainty we require for our regulatory proposals. We also encounter issues with customers churning to a retailer who does not allow the MC to share data with the DNSP, so we lose access to data from meters that we had previously been monitoring. From the MC's perspective, these trial contracts do not give any certainty of ongoing revenue in return for the MC's investment in the systems and interfaces required to provide the data.

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?

Yes.

The provision of basic power quality data to the DNSP is technically straightforward and is one of the basic functions that makes a smart meter a smart meter. Providing this data should simply be a requirement of the standard metering service, and any associated marginal cost should be included in the annuity paid by the retailer to the MC. In this case the cost to customers is restrained by competition between MCs, there is no need for additional contracts or unnecessary administrative costs, and customers don't end up paying twice for the basic functions that their smart meters were always intended to provide.

This does not preclude DNSPs negotiating commercial arrangements with MCs to procure more advanced data services, e.g. PQ data delivered at higher frequency than basic PQD, or other advanced meter services. Where a more advanced service has the characteristic that it is likely to be required for a subset of meters only, the DNSP may have some choice of MCs and hence a commercial tender process may be possible.

While the basic PQD service is straightforward, we recognise there are challenges in including the other two basic services recommended by the AEMC's working group – single meter enquiry and multi-meter ping – as part of the standard metering service covered by the MC's regular annual metering charge. These services are problematic because they are transactional, so the marginal cost to the MC to provide them will vary according to how much they are used, but they are also universal, so the monopoly issue still exists in any fee-for-service arrangement. In this case a fee-for-service with some kind of price regulation may be the best that can be achieved within the current framework.

QUESTION 16: REGULATORY MEASURES TO ENABLE INNOVATION IN REMOTE ACCESS TO NEAR-REAL-TIME DATA SOONER
QUESTION 17: REGULATORY MEASURES TO ENABLE INNOVATION IN LOCAL ACCESS TO NEAR-REAL-TIME DATA SOONER

While we can see the potential for future benefits for customers in having access to near-real-time metering data, in our view this is likely a longer-term opportunity, and one that requires further investigation around feasibility, costs and future benefits. The AEMC should focus its efforts in this review on the core issues identified that are negatively impacting customers today and preventing the benefits originally intended from being realised, namely:

- Accelerating the rollout
- Fixing the data access framework so that DNSPs receive basic PQ data from all meters
- Improving the meter replacement process

QUESTION 18: ADDRESSING SHORT TERM COST IMPACTS AND ENSURING PASS THROUGH OF BENEFITS

1. Are stakeholders concerned about the risk of short-term bill impacts as a result of the accelerated smart meter deployment? To what extent would the above offsetting and mitigating factors address this risk?
2. If stakeholders are concerned about residual cost impacts, what practical measures could be put in place to address these risks?

While a coordinated, accelerated rollout will bring forward some costs, it will also be more efficient than continued piecemeal meter replacement, and it will bring forward realisation of benefits for customers. Oakley Greenwood's analysis supports the intuition that net customer benefits are improved overall under a 2030 target for completion compared to a slower rollout.

3. What are the implications for AER revenue determinations for the upcoming New South Wales, Australian Capital Territory and Tasmania DNSP regulatory control periods? Is there a risk that network cost savings as a result of the accelerated smart meter deployment will not be fully passed through to consumers under the regulatory framework?

We note that there seems to be an underlying assumption in much of the 'beneficiary pays' narrative that benefits arising from DNSP access to meter data manifest as cost savings to DNSPs. This is true in some cases, e.g. where access to PQ data from smart meters means a DNSP can avoid some of the costs associated with investigating a local voltage issue or manual meter reading.

In other cases, however, the benefits manifest in improved customer service outcomes that the DNSP can enable by use of the data, that would not otherwise be possible, and these may be cost-neutral from a network perspective or may even involve some additional network expenditure to enable. An example would be the significant customer safety benefit of automatic neutral fault detection, which DNSPs can enable with only a small investment in data analytics once PQ data is available. Another would be the DNSP's ability to make available more export capacity to CER customers via flexible export limits than would otherwise be possible, as improved PQ visibility means that the DNSP can operate the network closer to its true limits rather than relying on estimates. As customer uptake of CER grows and the electricity system becomes more complex and dynamic, improved network visibility becomes increasingly critical in day-to-day operations to maintain a safe and efficient electricity network.

There will also be new costs to the DNSP from an accelerated rollout, e.g. in staffing to support its role in planning and administering the rollout and in coordinating multi-occupancy sites, in bringing forward costs associated with data storage and processing and in higher manual meter reading costs for legacy meters due to diminishing economies of scale.

To the extent that operating cost savings outweigh any new costs incurred during the regulatory period, the existing regulatory framework is designed to ensure that these savings are revealed and ultimately passed through to customers, as is the case with any other efficiency gain.

On the other hand, where networks incur un-budgeted costs in excess of savings, e.g. in supporting the accelerated rollout, the rule change should allow for cost recovery via a waiver of the normal cost passthrough threshold.

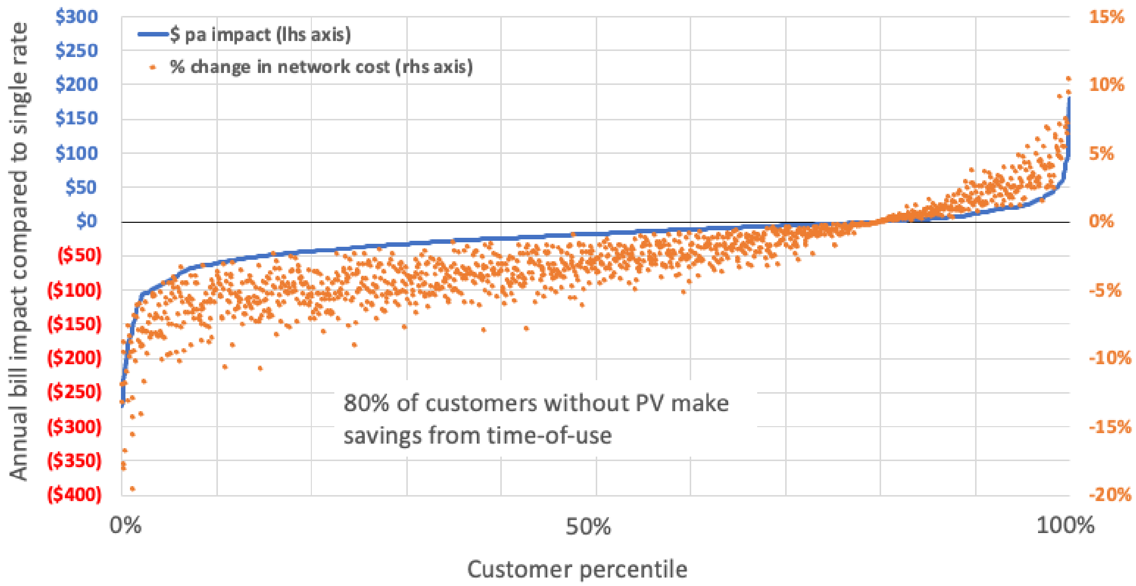
Attachment 2: tariff transition

We fully recognise the concerns of some stakeholders and customer advocates that transitioning customers from flat tariffs to time-of-use (or other cost-reflective) tariffs can result in higher bills for some customers, and that this can include vulnerable customers who may have little opportunity to change their behaviour to take advantage of the lower off-peak pricing periods.

It is important to understand, however, that many customers are increasingly disadvantaged by continued use of flat tariffs. Solar customers who are on flat tariffs today pay less than their share of network costs, pushing up prices for non-solar customers, including vulnerable customer cohorts.

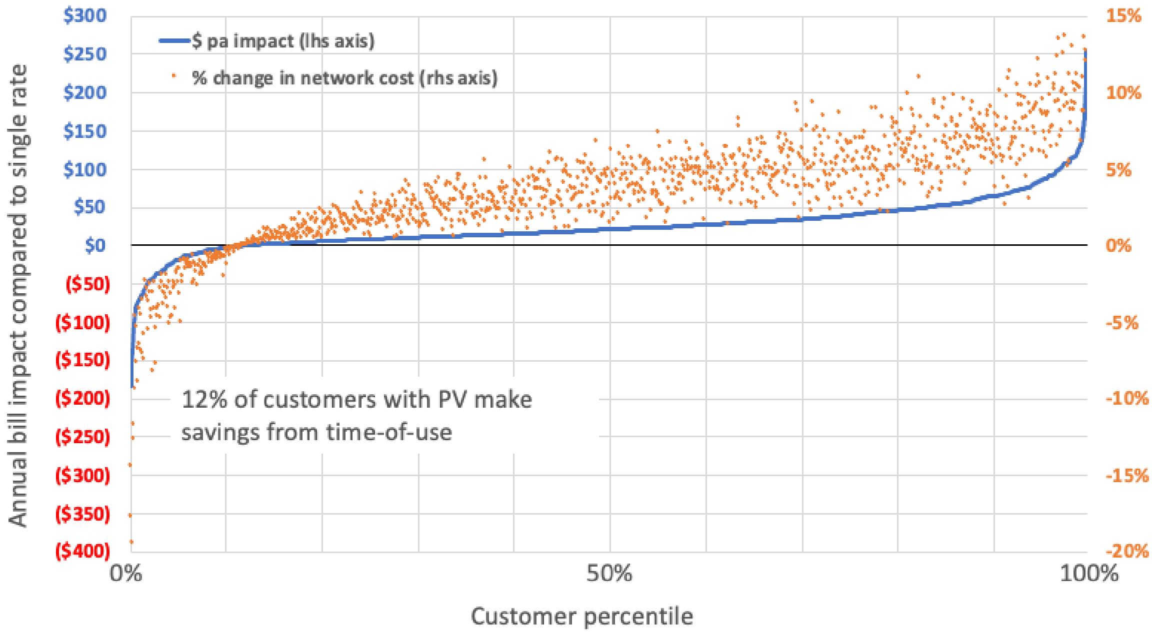
SA Power Networks' 'solar sponge' TOU tariff was designed with input from customers and customer advocates specifically to reduce this cross-subsidy while also protecting customers who are not able to respond to the price signal.

We have undertaken considerable customer impact analysis in the design of our 'solar sponge' TOU tariff. In a representative sample of 1,200 customers without solar PV, 80% of them will save money if they transition from a flat tariff to our TOU tariff, assuming no change in behaviour. Further savings are possible where customers can alter their behaviour to take advantage of the low overnight and even lower daytime rates. The TOU tariff thus creates the opportunity for non-solar customers to share in the benefit of abundant low-cost daytime solar in SA.



Bill impact analysis for 'solar sponge' TOU tariff – customers without PV

Correspondingly, 88% of solar customers will pay slightly more in network charges under the TOU tariff with no change in behaviour, because the level of cross-subsidy they receive from non-solar customers is reduced. Solar customers who can take advantage of the low-price periods by shifting their behaviour can still achieve savings – in this case savings that reward an actual contribution to the efficient use of the network rather than simply a subsidy from other customers.



Bill impact analysis for 'solar sponge' TOU tariff – customers with PV

Overall, we believe that cost-reflective pricing is in the long-term interests of all customers, and that calls to delay the transition to time-of-use pricing, while well-intentioned, risk actually harming those customers they are seeking to protect. Better tariffs are the key reason why we embarked on the transition to smart meters in the first place. They lead to more efficient use of the shared network infrastructure, reducing the need for network investment, and they enable the energy market to operate more efficiently, particularly in South Australia, by increasing the utilisation of abundant low-cost and zero-carbon renewable energy. Both these factors will reduce electricity costs for all customers in the long term and reduce inequities between customers with their own solar and other CER and those without.

Delaying the transition, or allowing those customers who may be worse off (because they currently enjoy a subsidy at other customers' expense) to opt-out, will delay benefits and tend to increase inequity.

Finally, we also note that by the time the new rules are in place we may already have transitioned around 50% of customers to TOU tariffs as part of a meter exchange process, and so introducing a mandatory delay on tariff transition for customers beyond that point could be perceived as unfair to all those customers who have already transitioned.