AEMC

REVIEW

Australian Energy Market Commission

DRAFT REPORT

REVIEW OF THE REGULATORY FRAMEWORK FOR METERING SERVICES

3 NOVEMBER 2022

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Energy Ministers' Meeting (formerly the Council of Australian Governments Energy Council). We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the Energy Ministers' Meeting.

SUMMARY

1 All consumers benefit from a more efficient and a lower-cost energy system. Smart meters are key to achieving this goal by providing the foundation to a more connected, modern and efficient energy system that supports future technologies, services and innovations. They are also an important tool that supports the decarbonisation of the energy market and other related sectors of the economy. The current metering framework already provides a pathway for legacy meters to be phased out over time, with smart meters being installed on a new and replacement basis — this is in addition to some proactive deployments by retailers, and through consumers' own requests. However, it is now clear that this approach will not lead to smart meters being deployed fast enough to support the transition to the future energy system.

2 Through the *Review of regulatory framework for metering services* (the Review), the Commission has worked collaboratively with a wide range of stakeholders to identify problems with the current framework, opportunities to improve customer outcomes and identify priority reforms that would accelerate smart meter deployment in the National Electricity Market (NEM).

3 The Commission is committed to progressing the deployment of smart meters in the NEM. This is a necessary investment to evolve the Australian energy system. A faster replacement of legacy meters will enable consumers to access the benefits that smart meters can provide.

4 This report sets out the Commission's draft recommendations to help accelerate the deployment of smart meters. The draft recommendations reflect many stakeholder ideas and suggestions put forward to the Commission in submissions and at the Review's forums and reference groups. Box 1 below provides a summary of the key recommendations.

BOX 1: KEY RECOMMENDATIONS

A new pathway to 100% uptake | The Commission recommends the target of universal uptake of smart meters by 2030 in NEM jurisdictions, where legacy accumulation and manually read interval meters are progressively retired by the distribution network service providers (DNSPs) under a legacy meter retirement plan, and retailers are required to replace the retired meters within a set time frame. Achieving a 'critical mass' of customers with smart meters can bring forward the provision of new and innovative services by retailers and third parties, and network benefits that participants will pass through to customers.

Enhancing existing metering arrangements | The Commission has identified opportunities to address problems with the current metering framework that have created process inefficiencies and led to poor customer experiences. The Commission recommends changes to the Rules that would reduce delays in meter replacements, facilitate coordination between market participants and empower customers to request a meter upgrade.

Supporting customers through the transition | The Commission recognises the need for transitional measures to support customers through the accelerated smart meter deployment program. The Commission recommends measures to create greater transparency for customers and information on how they can access the benefits, and customer safeguards to help manage change and provide greater assurances for customers who might be disadvantaged – including by potentially being assigned immediately to a cost-reflective pricing structure.

Unlocking new customers benefits | The Commission recommends new requirements to allow DNSPs, market participants and customers to access power quality data, which can provide for new value streams from customers' investment in smart meters. We consider the current arrangements for negotiating and utilising this data are not working as intended.

A 100 percent uptake of smart meters by 2030

5 The Commission recommends the target of universal uptake of smart meters by 2030 in NEM jurisdictions. This recommendation would have the most impact in New South Wales, the Australian Capital Territory, Queensland and South Australia. While this recommendation would also apply to Tasmania, the Commission notes that Tasmania already has a program in place to accelerate smart meter deployment. Victoria has already achieved a near-universal uptake of smart meters.

6 A 2030 timeframe is likely to be the earliest time that is realistically achievable by the industry. Feedback from stakeholders generally suggests that the metering industry is positioned well to scale up to deliver the additional deployments required under a 2030 target. The cost-benefit analysis outlined below shows there is significant economic benefits in accelerating smart meter deployment.

All consumers benefit from a more efficient and lower-cost energy system

7 Smart meters benefit individual consumers and the energy system as a whole. Household benefits include:

- enabling consumer energy resources (CER) – such as solar photovoltaic (PV) systems, home batteries and electric vehicles (EVs)
- providing consumers with visibility and control of their electricity consumption and costs – such as reduced estimated meter reads, better visibility of consumption, and more access to alternative pricing options
- improving safety outcomes – such as detection of neutral integrity failure, which can cause electrocution and 'tingles', and hot joints, which can cause fires.

8 Smart meters also create indirect, significant system-wide benefits to households – including benefits to DNSPs, retailers and the AEMO. For example, the data and information provided by smart meters allow DNSPs to improve their management of customer outages and, more generally, provide greater visibility of the low voltage (LV) network. Smart meters can offer a dependable and uniform pathway for near-real-time data delivery and control services.

9 DNSPs need to operate their networks more dynamically to manage the increasing uptake of CER. Smart meter data enables DNSPs to make better investment and operational decisions that could support more CER connections and potentially delay or remove the need for augmentation. This, in turn, allows for improved utilisation of network assets – which means higher productivity and lower average network costs for all customers.

A critical mass of smart meters will enable customers to access new services

10 Households will become smarter and more autonomous over time as they increasingly interact with the grid and energy markets (either passively or actively). Higher uptake of smart meters should open up a range of potential service options that better integrate CER into the energy system and allow customers to choose from different access and pricing services that best meet their needs and preferences. For example, 'solar soaker' tariffs that allow households to consume and (for some) charge their EVs in the middle of the day at very low or zero cost have been introduced by some DNSPs, and has seen significant customer and stakeholder support.

11 Realising the benefits of these new and innovative services is dependent upon a 'critical mass' of smart meters and data access – whereby economies of scale are required for market participants to justify new investments in innovative customer services. Many network benefits, which flow through to customers, also rely on a minimum uptake of smart meters, such as LV network optimisation.

12 Steps must be taken now to 'pave the way' to the future energy market. Many of the ESB's post-2025 Market Design recommendations and other industry reforms promote consumers' ability to participate in the NEM actively through their smart meters. The timely deployment of smart meters is a critical enabler for this forward work program. Further, smart meters create opportunities for greater data sharing that promote competition and innovation and more targeted energy policies.

There are clear economic benefits to accelerated deployment to achieve universal uptake

13 The Commission engaged an independent expert consultant to undertake an economic cost-benefit assessment of accelerating the deployment of smart meters across the NEM (excluding Victoria and Tasmania). The assessment considered the economic costs and benefits of an accelerated deployment of smart meters targeting 2030 in place of existing accumulation meters.

14 Overall, it was found there are significant net benefits from the accelerated deployment of smart meters. This finding holds even based on only a limited set of 'non-contingent benefits' that are highly achievable, including benefits derived from:

- reduced costs for routine meter reading and special reads
- the reduction in meter installation costs due to the scale economies of undertaking the deployment geographically
- the ability to de-energise and re-energise the premise remotely (though this feature may not be possible in all jurisdictions).

15 When including the benefits of enabling improved tariff design, especially 'solar soaker' tariffs, the cost-benefit analysis shows net benefits for:

- New South Wales and the Australian Capital Territory of $256 million
- Queensland of $197 million
- South Australia of $53.7 million.

Impact on customer bills

16 Customers' bill could increase in the short term as a result of the accelerated deployment of smart meters. The financial interactions between metering providers, retailers and customers can be complicated, and the AER does not regulate retail offers to customers.

17 Under current industry practice, retailers generally bundle all costs of supplying electricity, including metering costs, in their retail tariffs and customers do not face upfront costs when a smart meter is installed. Retailers also generally recover the cost of metering from all customers – i.e. customers with a smart meter do not face a higher metering charge. The Commission expects these arrangements to continue under an accelerated deployment of smart meters. Further, we consider the approach of retailers recovering metering costs through their customer base continues to be appropriate given all customers benefit from the accelerated smart meter program, as highlighted by the cost–benefit analysis.

18 The Commission is recommending new customer safeguards that require retailers to provide greater transparency on changes to tariff arrangements as well as any upfront charges that customers may face as a result of meter exchange. However, there may be a residual risk that consumers may face higher retail bills in the short term. The Commission is interested in stakeholder views on whether the transparency measures provide sufficient protection for customers, or whether additional safeguards are required.

New measures are needed to achieve a timely deployment of smart meters, but retailers and metering parties remain responsible for metering services for small customers

The performance of the metering framework and market outcomes have not met expectations

19 Outside of Victoria, the average smart meter uptake level in each jurisdiction is around 30 per cent. If the current installation rate continues, it will take at least another four to five years before a 50 percent uptake is achieved, and full deployment of smart meters may not occur until after 2040.

20 The current metering framework is not delivering the best outcomes for consumers. This Review has identified several issues with the current metering arrangements that have slowed progress and led to poor customer outcomes. For example:

- The pace of the deployment of smart meters has been slower than we anticipated for several reasons. Industry cooperation has proven to be a significant barrier — which appears to have been laden by market participants' misaligned incentives and the framework's complexity.

- Significant inefficiencies in the process lead to higher customer metering unit costs. Ombudsmen and AER complaints data highlight several implementation issues, like systematic installation delays.
- The installation of smart meters in the NEM has mainly been driven by consumers' requests to install solar PV systems or by new connections. Despite their crucial role in shaping the current metering framework, retailer-initiated smart meter programs have been minimal in most jurisdictions. Where smart meters have been installed, the scope of services offered to consumers has been narrow: some consumers do not see high-enough direct benefits to justify requesting a smart meter, other than those investing in CER.

Changes are needed to enhance the framework, but retailers and metering parties remain responsible for metering services for small customers

21 Without changes, the current framework is not capable to support the target of universal smart meter uptake by 2030. The Commission's draft recommendation contains two new key elements:

- a clear target outlining the desired level of smart meter uptake
- a preferred mechanism by which the target will be achieved.

22 The acceleration target and mechanism are not intended to be the only means by which smart meters can be deployed. The acceleration mechanism will be in addition to the existing types of deployments available under the current framework. Retailers can continue with their current strategies, and consumers can evaluate the benefits of alternative energy service offerings and request a smart meter themselves. A smart meter must still be installed for new connections and replacements.

23 The Commission also considers the current industry structure remains the appropriate arrangement to achieve accelerated deployment of smart meters. Retailers and metering parties will remain responsible for the provision of metering services for small customers.

24 The Commission notes that some stakeholders have urged the Review to consider recommending changes to return the responsibilities for metering to DNSPs. However, reassigning responsibilities for metering would require significant changes to the regulatory framework, the unwinding of contractual relationships between retailers and metering parties, as well as complications in transferring responsibilities for sites that have smart meters already installed. Such changes are likely to take significant time to implement and delay the ultimate goal of accelerating the deployment of smart meters and attaining the expected long-term benefits.

25 While there are issues with the current framework, the Commission considers that the current industry structure is more likely to deliver the benefits envisaged under the *Competition in metering* rule change, and innovation in technology and services to customers. The Commission understands that metering coordinators have been considering the deployment of next generation smart meter technologies as well as working with market participants to explore how smart meters could be used to deliver better retail and network services.

A package of reforms to help deliver the 2030 target

26 The Commission has explored potential regulatory pathways for delivering a universal uptake of smart meters by 2030. Further, to support an accelerated deployment, the Commission has considered ways to improve the efficiency of installation processes and industry logistics and address regulatory barriers and poor customer outcomes. These interventions seek to provide for a more consistent customer experience and minimise exceptions for customers to opt-out of the smart meter program.

27 Based on stakeholder consultation and the Newgate Research study conducted during the initial consultation stage of the Review, the Commission has identified steps in the installation process that can potentially lead to negative customer experiences. The Review explored the need for greater transparency and information provision to customers, and new customer safeguards to support customers through an accelerated deployment program. Additional benefits of smart meters can also be unlocked by creating greater access to power quality data.

Speeding up deployment of smart meters

28 Based on stakeholder engagement and feedback, the Commission identified and assessed several regulatory mechanisms that could help deliver an accelerated deployment (see Box 2 below).

BOX 2: OPTIONS FOR AN ACCELERATING SMART METER DEPLOYMENT

The Commission considered the following options to deliver a universal uptake of smart meter meters by 2030:

1. **Legacy meter retirement plan**: retiring legacy (type 5 and 6) meters and replacing them with smart meters under an industry-developed plan. Under this approach, DNSPs would be required to work with key stakeholders such as retailers, metering parties and jurisdictional governments to develop and publish a plan to retire their legacy meter fleet in a transparent and orderly manner to support the universal uptake of smart meters by 2030. Meters would be progressively retired by the DNSPs in accordance with the plan, and retailers required to replace the retired legacy meters within a set time frame. Retailers would report on their performance in undertaking meter replacements on a regular basis.
2. **Legacy meter retirement by Rules or Guidelines**: retiring legacy meters and replacing them with smart meters via Rules or Guidelines. Under this option, the schedule for the retirement of legacy meters will be outlined either via the Rules or a subordinate instrument developed by either the Australian Energy Regulator (AER) or Australian Energy Market Operator (AEMO). Retailers would be required to replace the retired meters within a certain timeframe and report on meter replacement performance.

3. **Retailer target(s)**: requiring retailers to achieve at least set levels of uptake of smart meters in line with the acceleration target. Retailers would undertake additional deployments to deliver on the target and report their meter replacement performance.
4. **Metering coordinator target(s)**: requiring metering parties to achieve a minimum level of smart meter uptake in line with the acceleration target. Under this approach, all legacy meters would be deemed to have retired at a given time. Retailers would be subsequently required to appoint an MC within a certain time. Metering parties must also report on their performance against the target.

29 The Commission recommends adopting an industry-developed plan using the legacy meter retirement approach. The legacy meter development plan would be coordinated by DNSPs to accelerate the deployment of smart meters to achieve universal uptake by 2030. This includes the setting of regular milestones — through yearly targets and compliance checks — to enable successful acceleration in smart meter deployment. The Commission considers that greater involvement of DNSPs would be crucial in driving an accelerated deployment by coordinating an orderly and transparent plan to retire legacy meters.

30 Under this approach, DNSPs will be required under the National Electricity Rules (NER) to develop a legacy retirement plan with input from key stakeholders and gain support. The AER will be required to approve this plan — either as part of the five-yearly regulatory proposal process or as a standalone process.

31 This approach enables better coordination of the deployment of smart meters as all parties will have visibility and input into the plan. For example, customers who are at multi-occupancy sites that are likely to have shared fusing could be scheduled to be retired simultaneously — supporting coordinated replacement and minimising the impact on customers.

32 A planned schedule of meter retirements can achieve significant economies of scale when meters are installed by geographical area. Having a high-level deployment plan at the start of the acceleration period would also provide greater certainty and clarity to the parties involved. This will allow metering parties to efficiently scale their operations to deliver on the required upgrades each year. Further, DNSPs can plan targeted upgrades in areas that can enable better visibility of LV networks.

Testing and inspection of legacy meters

33 As part of the implementation of the accelerated deployment program, the Commission also proposes to exempt legacy meters from regular testing and inspection requirements once the AER approves the legacy meter retirement plans. As part of DNSPs' legacy retirement plans, meters that are more likely to malfunction (e.g., those that have been installed for the longest time) could be targeted for priority replacement. Removing regular testing and inspection for legacy meters could contribute to reducing the cost of the accelerated deployment as DNSPs would no longer need to test and monitor assets that would be replaced in a short period of time.

A more efficient acceleration program

34 The Commission has identified steps in the installation process that can potentially lead to inefficiencies in replacing legacy meters and negative customer experiences. These issues can be addressed through the following reform initiatives:

- **Supporting customers to receive a smart meter from a retailer for any reason:** For situations where the customer's request does not include a connection upgrade or a rooftop solar system installation, the Rules currently do not provide explicit direction on whether retailers are obliged to install a smart meter. This has caused issues for some customers. The Commission therefore recommends clarifying in the NERR that retailers would be required to install a smart meter upon customer request.
- **Reducing the number of customer notices for retailer-led deployment to reduce confusion:** The Commission recommends that the number of notices a retailer must provide to a small customer when undertaking retailed led deployments under rule 59A is reduced from two notices to one notice. This should reduce administrative burden and costs, and enable greater flexibility, planning and coordination.
- **Consistent policy setting on opt-out:** The Commission recommends the removal of provisions in the NERR enabling customers to opt-out of a retailer-led deployment under standard retail contracts. Retention of the opt-out provisions could lead to customers indirectly incurring metering costs without access to the benefits, such as more accurate billing. It could also create inconsistencies with other reforms to address the multi-occupation issues. The Commission also considers that provisions for customers to opt-out of accelerated deployments should not be introduced.
- **Fit for purpose framework for replacing malfunctioning meters:** The Commission considers clear and reasonable timelines need to be in place to support timely meter replacements of malfunctioning meters. Separate timelines for individual and 'family' failures of meters are needed to reflect the different nature of the failures and the resources required by the metering parties to undertake the replacements in each case. The Commission recommends a longer replacement time frame for family failures than for individually identified malfunctions and removal of the exemption process to support timely meter replacements.
- **Processes to support timely remediation of customer-side defects:** The Commission proposes to implement a customer notification and record-keeping process for circumstances where metering coordinators encounter customer site defects. Better-defined arrangements are needed, especially for the accelerated deployment of smart meters. This will encourage more customers (who are willing and have the financial means) to remediate site defects and provide greater transparency for installers. Customers will remain responsible for remediating sites, although there is a strong case for government assistance programs — including financial support for customers to undertake site remediation.
- **Supporting better coordination for multi-occupancy scenarios:** The Commission recommends further developing and using a 'one-in-all-in' approach to meter replacements to improve meter replacement efficiency and customer experience in

scenarios where meters for customers on a shared fuse need to be replaced. These sites, typically found in multi-occupancy dwellings, pose a barrier to rolling out smart meters in certain areas and usually result in a negative customer experience. Under the 'one-in-all-in' approach, MCs will replace the legacy meters for all customers on a shared fuse simultaneously under a coordinated approach. This will make it easier to undertake meter replacements and improve customer experience on a shared fuse.

Supporting customers through the transition

Providing appropriate information to customers

35 The Commission considers greater transparency is required and recommends the provision of up-front, plain-language information to customers, including:

1. an information notice from the customer's retailer before the meter upgrade takes place
2. the development of a primary-source website to provide a single location that contains a trusted source of facts and information regarding smart meters and the accelerated deployment program.

Providing a transition period before tariff reassignment

36 The Commission recognises the accelerated deployment of smart meters could shift more customers to cost-reflective pricing structures sooner. The current network tariff framework allows customers to be automatically reassigned off their existing flat tariff structure when their legacy meter is exchanged. Stakeholders highlighted potential risks to customers of bill shock — consistent with insights from the Commission's customer research.

37 Although the current regulatory framework provides flexibility for DNSPs and the AER to develop tariff assignment policies that meet customer preferences in each jurisdiction, additional customer safeguards options may still be required to address uncertainty about how customers will be transitioned to cost-reflective pricing and provide greater assurances.

38 The introduction of a transition period, where customers would remain on their existing tariff arrangements, is one potential option. The Commission seeks stakeholder feedback on what other safeguards may be needed to address customer concerns.

Addressing privacy concerns

39 Privacy concerns were the second most significant barrier to customers requesting a meter in the Newgate study. This is an existing risk that may grow under an accelerated deployment – as more customers receive a smart meter sooner. Considering recent personal data breaches, including in the health and telecommunications sector, the Commission understands the potential for heightened customer concern about secure access to personal data and how participants will use personal data.

40 The Commission strongly supports the national privacy principles and their commitment to ongoing evaluation. Using the ESB *Consumer risk assessment tool*, the Commission considers it is vital that customers receive information about market participants' compliance with the *Privacy Act* through the relevant privacy policies. This should be provided in customer-friendly language through the new information provision. The Commission seeks feedback on this

concern as there may be opportunities to improve customer outcomes.

Unlocking further benefits from smart meters through better data access

41 A crucial enabler of smart meters providing more services is the access and exchange of power quality data they provide. Many of these benefits – and the services required to deliver the benefits – require consistent access to smart meter data.

42 The Commission has found that the current arrangements for negotiating and utilising data that the meter can provide are inefficient and likely don't contribute to the long term interest of consumers. We have developed a power quality data access to provide a consistent service structure. Stakeholders supported this new framework to enable greater visibility of the low-voltage network, promote standardisation, and support safety outcomes like neutral integrity detection and resolution. This should also allow for improved fault and outage detection, enabling faster reconnection for customers.

43 The Commission recommends that basic power quality data services should be exchanged on a minimum content basis and in a standard and agreed-on interface. Market participants should procure other services through the data access framework, such as meter inquiry - meaning the prices should be determined commercially.

44 There are regulatory changes the Commission could make to prepare the market for (near) real-time data innovations enabled by a critical mass of smart meters. These innovations directly and immediately benefit customers — especially by enabling other investments and choices to be optimised or provide broader benefits. Universal uptake of smart meters by 2030 will mean every consumer has access to apps and data services, which are enabling innovations that move the system closer to a real-time and more interactive market sooner. The Commission recommends new regulatory instruments which could be developed to manage different stakeholder concerns, including:

- Remote access – which retailers could facilitate by:
  - Default when their customers are in demand-side participation schemes or network support services.
  - An optional extra to the smart meter, like an opt-in carbon offset service.
  - Forming partnerships with new entrants to provide specialised and unique data services.
- Local access – which may require a customer's right in accessing the smart meter locally and in a specified way, inclusive of a process for activating or deactivating the local service.

45 The Commission received mixed views from the Review's Reference Group on the value of providing customers with access to (near) real-time data. Some of the Reference Group members suggested that (near) real-time data capabilities would be enabled in the long term organically, and regulatory intervention is not warranted. The Commission seeks stakeholder feedback on whether changes need to be made to the framework to better enable the delivery on (near) real-time capability.

An extensive and collaborative consultation process

46 The Commission is very grateful for stakeholders' high level of commitment throughout the metering review process to explore ideas and find the best outcomes for consumers. The knowledge and expertise of our stakeholders are invaluable and have significantly influenced our draft recommendations. Through the many discussions, we have considered different perspectives, underlying concerns and a range of possible solutions.

47 Under the Review's terms of reference, the Commission is required to consult with the AER, AEMO, energy departments of jurisdictions, consumer groups and ombudsmen of jurisdictions. Further, the Commission is partnering with Energy Consumer Australia (ECA) to better understand consumers' views on metering services.

48 The Commission established a Reference Group (with four Sub-Reference Groups) to facilitate a collaborative approach to the metering review and provide a consultative platform to discuss and stress test policy recommendations. The Commission also undertook several workshops, forums, and discussion papers on specific issues raised by stakeholders throughout the Review.

49 The Commission will continue to engage with stakeholders on the draft recommendations in this report and is committed to maintaining a highly collaborative approach to our engagement.

Next steps

50 The Commission encourages stakeholders to provide feedback on these issues and any other aspects of the Review's findings and recommendations. Submissions are due by **2 February 2023**.

51 The key project milestones are highlighted in the table below:

Table 1: Upcoming project milestones

MILESTONE	DATE
Submissions on the draft report are due	2 February 2023
Public forum	Last week of November 2022
Unilateral meetings	November 2022 – January 2023

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APPENDICES

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1 INTRODUCTION

In December 2020, the Australian Energy Market Commission (AEMC or Commission) self-initiated this *Review of the regulatory framework for metering services* (the Review). The purpose of the Review is to determine whether previous reforms introduced under the *Expanding competition in metering and related services* (Competition in metering) rule change have met expectations and whether changes are required to improve the efficiency and effectiveness of the regulatory framework for metering services. The Commission has also examined whether the regulatory framework for metering services supports the implementation of other electricity sector reforms where metering services will play a role.

The focus of the Review is residential and small business customers. For further background to the review, see the September 2021 Directions Paper and December 2020 Consultation Paper.[1] [2]

1.1 The Review seeks to achieve a more efficient and effective deployment of smart meters

The Commission developed the following objective for the Review in collaboration with the Review's Consumers Sub-Reference Group:

> To enable the deployment of appropriately capable smart metering to consumers in a timely, cost effective, safe and equitable way, and to ensure metering contributes to an efficient energy system capable of maximising the benefits for all consumers.

The objective recognises the role that meters play in delivering benefits — both to consumers individually and by enabling a more efficient and lower-cost energy system for all consumers. An efficient system that maximises the benefits for all consumers will, in turn, provide more significant benefits for all energy system stakeholders. The objective also recognises the importance of reducing barriers consumers face to realise the benefits.

The Review focuses on four areas:

- **Delivering for the consumer** | It is important that the framework delivers timely consumer benefits in a cost-effective, safe, and equitable way and that access is enabled for all consumers.
- **Services that meters should enable** | Barriers to services and data being delivered via a meter where the provision of those services via a meter is most appropriate should be minimised.

1 For the Directions Paper see here: https://www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf

2 For the Consultation Paper see here: https://www.aemc.gov.au/sites/default/files/2020-12/EMO0040%20Review%20of%20the%20regulatory%20framework%20for%20metering%20services-%20Consult%20paper%20FINAL%20v2.pdf

- **Driving the deployment of smart meters** | The regulatory framework should support a timely, cost-effective, safe and equitable deployment of smart meters where all consumers can access the benefits smart meters can enable.
- **Roles and responsibilities** | Exploring ways to improve cooperation, coordination and communication to improve the consumer experience and maximise benefits.

1.2 The Review's recommendations need to contribute to the achievement of the energy objectives

1.2.1 The national electricity objective and the national energy retail objective are the relevant energy objectives for this review

The Commission can only recommend changes to the regulatory framework in its reviews if it is satisfied it will or is likely to contribute to the achievement of the relevant energy objectives.

For this Review, the relevant energy objectives are the:

- **national electricity objective** |

  "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

  price, quality, safety and reliability and security of supply of electricity

  the reliability, safety and security of the national electricity system."

- **national energy retail objective** |

  to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.

1.2.2 The Commission has used a set of criteria to assess whether the Review's recommendations would likely promote the energy objectives

As part of the 2021 strategic plan, the Commission developed a set of assessment criteria that it would use to assess its decisions against the national energy objectives.[3] The Commission has therefore updated its assessment framework for the Review to align with the updated decision-making framework.[4]

The relevant assessment criteria for the Review are discussed briefly in the table below:

3 The assessment criteria can be found in *How the national energy objectives shape our decisions*, https://www.aemc.gov.au/media/99927.

4 In the consultation paper, the Commission put forward an assessment framework of: Transparency and predictability; Facilitating positive customer outcomes, including consumer choice; Efficient investment and allocation of risks and costs; Regulatory and administrative burden; and System integrity.

Table 1.1: Assessment criteria for the Review

CRITERIA	EXPLANATION
Outcomes for consumers	• The Review's recommendations should deliver better consumer outcomes regarding metering services. • The Review's recommendations should be compatible with developing and applying consumer protections for small customers – including protections relating to hardship customers.

Implementation considerations	• The Review's recommendations should consider:
	  • implementation and ongoing costs and their proportionality to the expected benefits
	  • the likelihood of uptake and impact across different consumer segments and market participants
	  • whether the recommendations could achieve NEM-wide success by considering specific jurisdictional considerations, issues, and benefits.

Innovation and flexibility	• The Review's recommendations should encourage innovation that benefits consumers in new services or ways of providing existing services. • The Review's recommendations should be flexible to accommodate new approaches without needing further updates to the Rules. Sometimes, the Commission's approach may be prescriptive to narrow or even broaden the space for innovation in the face of complexity or risk.

Principles of market efficiency	• The Review's recommendations should consider how reforms to the metering framework will contribute to the lowest possible total system cost and whether proposed reforms would support new and innovative energy services and thereby promote:
	  • allocative efficiency — enabling market prices that facilitate the allocation of electricity to their highest-valued uses
	  • productive efficiency — enabling operational signals to facilitate dispatch of the least-cost mix of electricity supply to meet demand
	  • dynamic efficiency — minimising barriers to entry and promoting efficient investment in energy markets, consumer energy resources and distribution systems to meet electricity demand over time.
	• The Review's recommendations should consider whether risks are allocated to those who are best placed to manage them

CRITERIA	EXPLANATION
	and have the incentives to do so.
Safety, security and reliability	The Review's recommendations should promote the safety, reliability and security of supply.
Decarbonisation	The Review's recommendations should lead to a more coordinated, efficient approach to consumer, investor and policy decisions to decarbonise the energy sector.

1.3 This Draft Report

1.3.1 Setting out recommendations to deliver a higher uptake of smart meters, faster

In the Review's Directions Paper, the Commission set out high-level changes to the regulatory framework that could help realise the benefits of smart meters to consumers and the electricity system. In submissions to the Directions Paper, most stakeholders supported the Commission's key position that a high uptake of smart meters is needed to deliver benefits to consumers and the electricity system. Many submissions also supported the Commission to consider options to accelerate smart meter deployment so that a critical mass can be achieved promptly.

This report contains the Commission's draft recommendations on necessary measures to accelerate the deployment of smart meters and supporting changes to the regulatory framework that address barriers to a faster smart meter deployment program. These draft recommendations reflect a highly collaborative consultation process – with significant input from a broad range of stakeholders.

1.3.2 How this report is structured

The Draft Report is structured as follows:

- Chapter 2 explains why the Commission recommends the target of universal uptake of smart meters by 2030 in National Energy Market (NEM) jurisdictions – including our vision for the crucial role smart meters play in the future, and identifying problems with the metering framework that have created inefficiencies and delays under the current rollout program.
- Chapter 3 provides a summary list of the Commission's 20 recommendations — highlighting the mechanisms to implement the proposed changes, with cross-references to the relevant appendix chapters in the report.

The appendices that follow outline in detail the key issues, stakeholder views, the basis for our recommendations, and further consultation questions to guide stakeholder submissions:

- Appendix A outlines the target of universal uptake of smart meters by 2030 in NEM jurisdictions, including options for measures to accelerate.
- Appendix B and appendix Coutline opportunities to address problems with the current metering framework that have created inefficiencies and led to poor customer experiences.

- Appendix C also outlines the need for transitional measures to support customers through the accelerated smart meter deployment program.
- Appendix D outlines new access arrangements for exchanging data between Metering Coordinators (MCs) and Distribution Network Service Providers (DNSPs), as well as enabling innovations for consumers to access real-time usage data while maintaining trust and confidence in data exchange.
- Appendix E outlines energy market reforms that rely on smart meters as a critical enabler.
- Appendix F and appendix G provides a detailed summary of the cost-benefit assessment prepared by independent consultant Oakley Greenwood — including the underlying assumptions applied by Oakley Greenwood, and the Commission's further consideration of the timing of costs and benefits under an accelerated deployment, and the implications for retailers and customers.
- Appendix HH provides a list of questions to the draft recommendations.

1.4 Lodging a submission

Written submissions on this Directions Paper must be lodged with Commission by **2 February 2023** online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code EMO0040.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Mitchell Grande on (02) 8296 7800 or Mitchell.Grande@aemc.gov.au.

2 WHY WE NEED TO ACCELERATE THE DEPLOYMENT OF SMART METERS

2.1 A target of universal smart meter uptake by 2030 will support the transition to the future energy market

The energy landscape is undergoing unprecedented change in response to market and technology developments, changing community expectations and the shift to a cleaner energy system. Consumers have driven much of this change by installing consumer energy resources (CER) such as solar panels and, increasingly, battery storage and electric vehicles. The rapid uptake of CER has already delivered significant benefits to households and is playing a major role in supporting the nation's net zero emission target.

Smart meters play a crucial role in the electricity system's transition. The Commission's key recommendation of this review is the target of universal uptake of smart meters by 2030 in NEM jurisdictions. A 2030 time frame is likely to be the earliest time that is realistically achievable by the industry. This recommendation would have the most impact in New South Wales, the Australian Capital Territory, Queensland, and South Australia. While this recommendation would also apply to Tasmania, the Commission notes that Tasmania already has a program in place to accelerate smart meter deployment. Victoria has already achieved a near-universal uptake of smart meters.

Steps must be taken now, and investment brought forward to 'pave the way' to the future energy market. As an enabling technology, smart meters support new service options for customers — providing opportunities to participate in the energy market and the efficient distribution system operation. These are necessary to transition the current electricity system to one that is smarter, more integrated, and takes full advantage of the opportunities provided by the technological change in metering (sections section 2.1.1-section 2.1.3). A higher uptake of smart meters and greater data access are needed to realise many benefits (section 2.2).

Progress in rolling out smart meters has been slow and inefficient to date. Outside of Victoria, the average smart meter uptake level in each jurisdiction is around 30 per cent. If the current installation rate continues, it will take at least another four to five years before a 50 per cent uptake is achieved, and full deployment of smart meters may not occur until after 2040. This time frame is not sufficiently ambitious. The Commission has identified several problems with the current metering arrangements that have slowed progress and led to poor customer outcomes — as highlighted by many stakeholder submissions (section 2.3).

We engaged an expert consultant to undertake an independent cost-benefit analysis of an accelerated smart meter deployment. We are satisfied that our recommendation to initiate meter replacements sooner will result in significant net benefits to customers (section 2.4).

2.1.1 Future market design relies on the digital foundation provided by smart meters

Technology developments are allowing consumers to participate in the energy sector in ways

that were not possible a few years ago

Technological improvements that enable remote communication, control and automation of consumer devices combined with developments in artificial intelligence and cloud-based services are allowing consumers to become more active and involved in the energy sector. As Wattwatchers submission to the Review indicates, such changes are already happening:[5]

> … a tech-driven, data-rich electricity future with high uptake of DER is inevitable, and is already clearly taking shape. Information and communications technologies, cloud analytics, and IoT with machine learning and artificial intelligence (AI) will be vital to this 'New Energy' or 'Grid 2.0' future.

Smart meters provide a vital capability for consumers to be part of the energy system transition

In the long term, technology-enabled consumer interactions will help facilitate a more open and flexible energy market. PIAC state:[6]

> Collectively, consumers without appropriately capable metering reduce the ability of the system to operate efficiently, reliably and affordably in their interests. Reforms and rapid technology changes already underway make capable metering even more important to the consumer interest.

Smart meters will support greater competition[7], and new business models will emerge over time. For example, through collective engagements, small and large consumers have opportunities to participate in new and emerging services – such as virtual power plants (VPPs).

The Commission's overarching reform objective is to evolve the electricity market framework to optimise the provision of multiple CER services to maximise the benefits for the broader community.

Smart meters are important in the transition to net zero emissions

Smart meters are a critical enabling tool for an orderly transition to net zero. We recognise that decarbonised, affordable and reliable energy is a key enabler of economic growth and improved consumer living standards. [8]

Decarbonisation is a significant focus for the energy sector. State and Commonwealth governments have recently committed to a 43 per cent reduction in emissions by 2030 and net zero by 2050 and adopted a range of policy initiatives to meet this objective. Investors increasingly consider decarbonisation in environmental, social and governance criteria.

5 Wattwatchers submission to Directions Paper, p. 2.

6 PIAC submission to Directions Paper, p. 8.

7 Customer churn or transfers between retailers is a much easier process with smart meters – allowing for nearly instant reads of customer data.

8 More information can be found here: https://strategic-plan.aemc.gov.au/strategic-identity

Household investment in consumer energy resources such as rooftop solar and batteries reflects environmental concerns. Climate change itself also affects the security and reliability of our energy system. Climate change makes extreme abnormal conditions increasingly frequent and impacts weather-dependent generation technologies. As a result, unforeseen and unexpected threats to the power system are emerging. Our decisions must consider how these fundamental shifts interact with our rules and how best to encourage an efficient, coordinated approach to the transition. [9]

The South Australian Government state that the data provided by smart meters can assist DNSPs to integrate CER better and increase their ability to host such resources. [10] A high uptake of smart meters will enable innovation in energy markets and converging sectors such as transportation. For example, a smart meter-enabled grid could support the electrification of transport through higher and more efficient uptake of electric vehicles.

Many of the Energy Security Board's (ESB) post-2025 Market Design recommendations and other industry reforms promote consumers' ability to actively participate in the NEM through their smart meters. The timely deployment of smart meters is a critical enabler for this forward work program (see appendix E).

2.1.2 Smart meters will enable retailers and energy services providers to develop new service and pricing options

A higher uptake of smart meters should open up a range of potential service options and allow customers to choose from different access and pricing services that best meet their needs and preferences. Smart meters create opportunities for greater data sharing that promote competition and innovation and more targeted energy policies. Consumers can control their appliances through a mobile app or hub-based service to take advantage of times when energy prices are low.

Retailers could also provide customers with smart meters access to real-time data and services that allow them to manage their usage better and understand and forecast their electricity bills. Aurora Energy' new 'Aurora+' app, which provides real-time data service services, has seen significant customer uptake with very positive feedback and government support.

ECA's submission to the Directions Paper highlight the value of products that are enabled by data provided by smart meters:[11]

> The key value of a smart meter to consumers is not that they facilitate easier billing, or that networks can use this data to make efficient investment decisions. The value for consumers is that granular data, can unlock a service or product that they value, whether this is a service provided though an aggregator or a directly through an app or a portal. Newgate Research's findings tell us that consumers would value access to dollar usage in real-time. This is also found in our Energy Consumer Sentiment Survey

9 AEMC, How the national energy objectives shape our decisions, October 2022, p. viii.

10 South Australian Government submission to Directions Paper, pp. 1-2.

11 ECA submission to Directions Paper, p. 4.

that 60% would reduce their electricity consumption if they had access to their overall energy usage and a breakdown of appliance energy usage.

Innovative third-party service providers can help customers to automate and optimise household devices to minimise customer bills and maximise the value of the CER investments. This can be achieved through increasingly affordable automated home energy management systems with technologies that can respond autonomously to more advanced price signals while minimising impacts on people's day-to-day lives.

2.1.3 Smart meters will also help distribution network businesses to run their networks more efficiently and develop products that support more CER to be connected to the grid

Smart meters can provide DNSPs with significant opportunities for DNSPs to improve the utilisation of their networks, which could lead to lower average network costs for all customers in the long term. Smart meters can collect more granular data about the condition and capacity of the low voltage (LV) network. Through a combination of smarter network management and customer rewards, spare network capacity can be utilised by flexible CER, thus reducing the potential need for expensive future network augmentation.

DNSPs such as SAPN in SA and Citipower and Powercor in Victoria are beginning to offer 'solar soaker' tariffs in the middle of the day that allows households to consume electricity at very low or even zero cost. These developments have significant customer and stakeholder support across jurisdictions.

Innovative network approaches that support more CER to be connected also require more smart meters. A better understanding of the LV network capacity, through data collected by smart meters, allows some DNSPs to develop flexible export arrangements for customers with CER. Instead of relying on static export limits, DNSPs could offer CER customers significantly higher export capacity when the network has a significant capacity (or need) for electricity exports.

2.2 A critical mass of smart meters is required to deliver benefits to consumers and systems

2.2.1 Most stakeholders support a high uptake of smart meters

Most stakeholder submissions highlight that the realisation of the benefits of new and innovative services is dependent upon a critical mass of smart meters and data access — whereby economies of scale are required for market participants to justify further investments in innovative customer services.[12]

12 Submissions to the Directions Paper: ActewAGL, p. 3; AGL, pp. 3–4; Alinta Energy, p. 3; AEC, p. 2; CEC, p. 4; CitiPower, Powercor and United Energy, p. 3; EDMI, pp. 2-3; Endeavour Energy, pp. 8-9; Essential Energy, p. 4; EWON, p. 2; Green Metering, p. 3; 9; Gridsight, p. 2; Landis+Gyr, p. 4; PLUS ES, pp. 5–6; SAPN, p. 2; Solar Analytics, p. 3; Secure Meters, p. 3; Origin, p. 2; PIAC, p. 7.

Intellihub state that the current smart meter installation rate means that many customers and the broader energy system will continue to miss out on the benefits of smart meters unless the deployment is accelerated.[13]

AGL acknowledge that a higher uptake of smart meters will allow consumers and other market participants to realise the associated benefits fully. However, it also raises concerns regarding the costs of achieving a higher smart meter uptake and estimated that 70 per cent smart meter uptake would be sufficient to deliver consumer benefits.[14]

> … the costs associated with setting up systems, applications, and customers portals, especially large-scale operations, are considerable while customer responsiveness and appreciation is still developing. … A higher uptake of smart meters will encourage parties to keep exploring additional value-add services which can be enabled by smart meters and promote further growth and adaption of emerging technologies, although exactly how much growth is as-yet unknown.

Many of the direct benefits to DNSPs and retailers — which flow through to customers — also rely on a minimum level of uptake of smart meters, such as LV network optimisation. ENA's submission to the Directions Paper provides an indicative summary of services DNSPs can provide, and the minimum and optimal data uptake required to deliver benefits to customers.[15] DNSPs demonstrate that these services may also require more explicit data access or a geographically significant spread of smart meters before realising consumer benefits.[16] CEC submits that there should be 100 per cent smart meter uptake to enable equitable implementation of tariff reform.[17] CitiPower, Powercor, and United Energy considers:[18]

> … as we transition to the post-2025 NEM design, and distributors take on the role of the distribution system operator (DSO), any uptake below 90% will be insufficient for the type of dynamic network management that is envisaged in the future. As DER uptake grows, and behind the meter systems become more sophisticated, smart meter data will be crucial in facilitating efficient dynamic solutions and eventually dynamic pricing. Real time meter data is required to monitor each circuit in the LV network to produce dynamic 'operating envelopes' for DER.

Some stakeholders do not agree. For example, Edge Electrons does not consider that universal smart meter uptake is required to deliver the network operations benefits. Smart meters are a significant annual cost burden with minimal financial benefit for customers who do not adopt CER or choose to participate in time-of-use tariffs. Edge Electrons states:[19]

13 Intellihub submission to Directions Paper, p. 2.
14 AGL submission to Directions Paper, p. 3-4.
15 ENA submission to Directions Paper, pp. 20–23.
16 AEMC, Directions Paper, 16 September 2021, p. 78.
17 CEC submission to Directions Paper, p. 4.
18 CitiPower, Powercor and United Energy submission to Directions Paper, p. 3.
19 Edge Electrons submission to Directions Paper, p. 9.

> … The failure of retailers to persuade non-DER customers to adopt smart meters outside Victoria under the Power of Choice legislation is, however, clear evidence that retailers and DNSPs are unable to articulate a compelling case for smart meters with all customer segments, especially the lower income, vulnerable customers.

2.2.2 Consumer advocates urged a universal deployment to ensure all consumers are able to have access to benefits provided by smart meters

Customers without CER can still benefit from system transition, but they need smart meters to access the benefits

While the increasing uptake of CER has delivered significant benefits to both the system and consumers who invested in them, the benefits are not always available to all consumers. There is a proportion of customers who are not able to benefit from the transition because they do not have the ability to invest in CER or actively participate in CER markets.

The Commission considers that reforms and changes to the regulatory framework should benefit all consumers to the extent possible. Smart meters will enable customers without CER to benefit from the system transition by providing access to programs such as solar soaker tariffs and a better understanding of their energy usage data as described above. Non-CER customers can only realise these benefits if they have access to smart meters. ECA states:[20]

> Currently, there is large unrealised potential for services to be developed which use smart metering to support vulnerable customers. Easy and convenient access to energy usage data is critical not just for consumers with DER but also for those who can find ways to economise. Energy usage data made easily accessible and convenient for consumers can help them plan for and reduce their energy costs. The deployment of smart meters in the UK saw some retailers develop innovative new services tailored to vulnerable consumer needs which made considerable impact on the ease at which they managed their payments. In addition to close to real time data access, smart meters can also help vulnerable consumers understand what retail tariff structure might provide the lowest cost and most suited service for them.

Consumer advocates support a universal deployment of smart meters

In their submissions to the Direction Paper, other consumer advocates such as ACOSS et al. and PIAC considered smart meters to be essential infrastructure that facilitate the energy system transition and urged the Commission to consider a universal deployment.

ACOSS et al.states:[21]

> The AEMC should recognise smart metering as essential infrastructure, to facilitate access to clean, affordable and dependable energy for all. In recognising the essential nature, develop options to ensure fast and equitable access of smart metering for all

20 ECA submission to Directions Paper, p. 2.

21 ACOSS et al. submission to Directions Paper, p. 4-5

> households, with appropriate protections to deal with any potential downsides of smart metering … The AEMC should recommend a universal scaled deployment of smart metering, to ensure equitable access to essential smart metering for all households, and for the full range of smart metering benefits to be realised.

PIAC's submission echoes a similar sentiment. In response to the Directions Paper's question on whether stakeholders consider a high uptake is needed to realise the benefits of smart meters more fully, PIAC submits:[22]

> All consumers require appropriately capable metering. Equity of access to capable metering must be considered the priority … Prioritising equity of access to appropriately capable metering should be the primary motivation for faster deployment. This will ensure scale is reached and help ensure that no consumers are excluded or unfairly disadvantaged in the deployment process.

2.2.3 Smart meters *and* other technologies: ecosystems thinking for the future

Throughout the Metering Review, the Commission understands that there are alternative devices that can provide services and data outcomes that are substitutes or complementary to smart meter outcomes. As recognised by the ECA, there is a need for a holistic consideration of the range of devices and how they work together under an accelerated deployment, stating:[23]

> The Directions Paper notes the concern raised by multiple stakeholders that smart meters might not be the right device to deliver wider consumer benefits in the form of improved and/or innovative energy products and services… In saying this we would still like to encourage the AEMC to remain aware as part of their review of the developing state of technologies and services available to consumers that exist outside of smart meters

A broad group of stakeholders support the role of the smart meter in providing typical and additional services as a vital part of the future grid – recognising opportunities to expand this role to support consumer-first services, e.g., achieving universal coverage of edge devices in the network, enabling new and dynamic use cases, as well as lead to a more coordinated, efficient approach to consumer, investor, and policy decisions to decarbonise the energy sector.[24]

The Commission does not expect smart meters to solve all emerging system issues either, as SolarAnalytics explains:[25]

> The energy transition is being driven by the increasing uptake of DER. Smart Meters

22 PIAC submission to Directions Paper, p. 7

23 ECA submission to the Directions Paper, p. 4.

24 Submissions to the directions Paper: AGL, p .3; AEC, p. 1; Alinta, pp. 3, 6; Bright Spark, p. 2; CitiPower, p. 3; EDMI, pp. 1-2; Endeavour, p. 12; EnergyAustralia, p. 7; Gridsight, p. 6; Itron, p. 8; MEA Group, p. 1; PIAC, p. 11; Secure Meters, p. 2; Telstra, p. 2.

25 Solar Analytics submission to the Directions Paper, p. 5.

> are unable to address these [emerging system issues] and changes effectively because:
>
> - They are not able to efficiently manage the complex variety of different DER
> - They are not owned or controlled by the consumer, who has purchase the DER and has the greatest stake in how their DER is operated

Technology choices must be made in the context of the NEM's technological innovation and market reform. The choice of smart meters is deliberate – to encourage all customers to receive at least the broad and general metering service outcomes, thereby setting a technical floor in the system, as PIAC considers:[26]

> New services and platforms are likely to require other devices to operate alongside meters to manage and monitor usage, generation and storage.
>
> This does not lessen the requirement for capable metering to be available to all consumers.
>
> All consumers should have access to metering capable of delivering energy services with suitable accuracy, safety and flexibility

Smart meters will be just one source of services and data across the distribution network to deliver the benefits of the future grid. From Draft Report to Final Report, the Commission would like to continue an open engagement on what the future grid could and ideally should look like concerning 'all of the above' devices — not either/or.

2.3 The current regulatory framework is not facilitating the best outcomes for customers

The Commission introduced the current metering framework through the *Competition in metering* rule in 2015 to encourage commercial investment in smart meters and associated services. The rule only required a smart meter to be installed for small customers on a new and replacement basis. Retailers were also provided with the ability to undertake retailer-led deployments and small customers could also request a smart meter to be installed if they choose to do so.

At the time, the Commission considered metering competition would enable improved customer outcomes. Retailers and customers could choose to replace their legacy meters with a smart meter where there is a clear benefit.

As set out in the Directions Paper, the performance of the metering framework and market outcomes have not met the expectations set out in the original rule:

- **The pace of the deployment of smart meters has been slower than anticipated for several reasons**. For example, industry cooperation has proven to be a significant

26 PIAC submission to the Directions Paper, p. 11.

barrier — which appears to have been created by misaligned incentives of market participants and the complexity of the framework.

- **Significant inefficiencies in the process lead to higher customer metering unit costs**. Ombudsmen and the Australian Energy Regulator (AER) complaints data highlight several implementation issues, like systematic installation delays.
- **The deployment of smart meters in the NEM has mainly been driven by consumers requests to install PV systems or by new connections**. Despite their key role in shaping the current metering framework, retailer-initiated smart meter programs have been minimal in most jurisdictions. [27] Where smart meters have been installed, the scope of services offered to consumers has been narrow. This means some consumers are not seeing high-enough direct benefits to justify requesting a smart meter – other than those investing in CER.

2.3.1 Smart meters are not being rolled out fast enough

Stakeholders such as the CEC and South Australian Government consider the deployment of smart meters to be piecemeal, ad hoc, and slower than expected. ACOSS et al. considering the current approach mean that many people experiencing financial or social disadvantage could be the last to access smart metering and miss out. [28]

Other submissions highlight regulatory barriers preventing a faster deployment, including:[29]

- fragmented jurisdictional regulatory frameworks for smart meter installation and services –whereby some state/territory governments have prohibited potential benefits to retailers (such as remote disconnections)
- the Default Market Offer (DMO) does not include the cost of smart meters in its regulated prices and related reference bill for every state
- strict regulatory compliance requirements and operational inefficiencies in the meter malfunction exchange process – with limited incentives for retailers to initiate DNSP meter family failure Type 4 deployments due to poor site compliance, the potential cost to the customer and a cohort of customers refusing the upgrade
- expensive and sometimes unnecessary physical field assessments before meter installations can take place
- site access issues (multiple occupancy dwellings) requiring the provision of DNSP and/or landlord keys to access locked sites and meter rooms.

Stakeholders consider that the current framework requires extensive coordination between many parties, with incentives misaligned or unclear. For example, Tesla submits coordinating the installation of smart meters with CER installations can be challenging and lead to significant delays due to both having multiple parties required to enable a smart meter

27 EWON submitted "Retailers pushed for reform and the expectation was that the smart meter deployment would be proactively led by them. Retailers have not lived up to the responsibility of the deployment for which they heavily lobbied." (p. 3) CEC submitted "It was electricity retailers that argued during the development of the Competition in metering policy that they should be given the sole role of leading the smart meter deployment across the NEM. They should not be let off the hook … ." (pp. 5–6).

28 Submissions to the Directions Paper: CEC, p. 1; South Australian Government, p. 2; ACOSS et al., p. 5.

29 Submissions to the Directions Paper: ActewAGL, p. 5; AGL, p. 1.

installation and requirements for smart meters to only be installed by accredited third-party metering installers.[30] Intellihub notes smart meters can deliver benefits to a wide range of parties across the energy sector, but all the costs are generally borne by retailers.[31] These incentive issues are considered in more detail below.

2.3.2 Mixed incentives

Evidence suggests that retailers only deploy smart meters where there is a clear business case; however, not as proactively as was envisaged under the Competition in Metering rule. The expected competitive pressures and commercial incentives have not been strong enough – in part due to low uptake rates limiting retailers' ability to achieve economies of scale (as discussed in section 2.1 above). Metering parties, retailers and DNSPs indicated that they find it hard to coordinate meter installation, as well as come to commercial arrangements with the provision of services and data.

Stakeholders indicate that the combination of a vertically-separated industry structure and the current regulatory setting mean that the benefits of widespread uptake of smart meters are divided between several parties, but the responsibility for the deployment is vested in only one market participant category — the retailers. Incentives for retailers to accelerate meter uptake are not clear, and while DNSPs would benefit from greater uptakes of smart meters, DNSPs currently bear none of the costs or logistic and administrative burdens. ActewAGL stated:[32]

> Retailers bear the risk of providing smart meters to customers and are often faced with significant costs that cannot be adequately recovered. The existing regulatory framework does not support a rapid deployment of smart meters because there is a misalignment of incentives, with key beneficiaries [DNSPs and MCs] not sharing the costs or risk of the deployment.

Similarly, Bright Spark Power submits:[33]

> … the issues and difficulty faced by retailers when deploying meters (such as, strict messaging criteria, multi-dwelling premises with shared fusing, asbestos switchboards, non-compliant panels etc.) have created an environment where all the cost of deployment is exclusively attributed to the retailer, which disincentivises the activity i.e. retailers carry all of the cost, some of the benefits, and majority of the disruption risk.
>
> … retailers do need to be supported by the other market participants to enable a lower cost and reduced deployment complexity of Smart Meters, through sharing of information such as, identification of premises that are non-smart meter ready, via a centralised systems that include premise Smart Meter Readiness status for each NMI/supply address.

30 Tesla submission to Directions Paper, p. 3.
31 Intellihub submission to Directions Paper, pp. 2, 6.
32 ActewAGL submission to Directions Paper, p. 1 (cover letter).
33 Bright Spark Power submission to Directions Paper, pp. 2-3, 4.

Commercial incentives for metering service providers to deliver value-add outcomes to consumers or third parties are also unclear. This may be due to: incentives for DNSPs to utilise capital expenditure over operating expenditure,[34] a lack of scale of smart meters, confusion relating to accountability or ability to provide additional services under the current framework, and lack of clarity around cost recovery. For example, DNSPs have reported difficulties negotiating consistent, secure, cost-effective access to asset and engineering data.[35] In contrast, Alinta Energy stated:[36]

> While we understand that third parties may encounter difficulties negotiating with providers of advanced meter services, the main contributor to split incentives is a failure to negotiate between parties that could jointly benefit from a commercial arrangement.

Endeavour Energy submitted it has strong reservations about any arrangements for DNSPs to contribute to the cost of installing meters to stimulate a retailer-led deployment, and considered competition between retailers should continue to underpin the incentives that retailers have to deploy smart meters. Endeavour Energy says sharing the installation costs of a retailer-led deployment would introduce significant complexities related to efficient pricing, cost allocation and cost recovery. [37]

2.3.3 Process inefficiencies are leading to higher overall costs for customers

The Commission considers process inefficiencies due to complex relationships, unclear objectives and separation of responsibilities, geographical challenges, and incentive problems. This includes legacy electrical and installation issues that are not within the metering regulatory framework's scope but are impacting the effectiveness of its operation.

For example, under the current arrangements, meters are generally replaced one-by-one, rather than by area, with meter providers incurring high costs in travelling to individual sites. These costs are exacerbated in regional areas where installers may have to travel long distances to visit a site. This limits scale efficiencies, which means higher unit costs for customers (as demonstrated by the cost-benefit analysis outlined in section 2.4). The AEMO submits:[38]

> Currently, most meter installations result from a customer request such as a new connection or installation of a solar PV system, or the replacement of malfunctioned metering installations.

34 Alinta Energy submitted "One approach that could encourage improved alignment of incentives would be for the AER to require DNSPs to seek market-based solutions (rather than through the economic regulation of network costs) to network monitoring and other services that could be procured from the competitive market (MCs)." (pp. 5–6) Similarly, AEC submitted "distribution networks have still not forged strong commercial relationships with metering providers and data managers to obtain information on voltage and faults management that might be available, and instead are still pushing for capex to establish a duplicate capability themselves." (p. 1).

35 For example, Ausgrid submitted "Retailers, not network businesses, choose the metering provider at particular locations, which may be critical for network performance monitoring. Therefore, the network businesses have limited ability to negotiate pricing." (p. 6)

36 Alinta Energy submission to Directions Paper, p. 5.

37 Endeavour Energy submission to Directions Paper, p. 10.

38 AEMO submission to Directions Paper, p. 2.

> Smart metering installation resulting from these reactive sources is inherently inefficient – ad-hoc, often unplanned and geographically dispersed. Whilst it might be possible for a Metering Coordinator to obtain some efficiencies from combining customer service provision and malfunction rectification, the lack of a comprehensive proactive metering replacement program means that potential greater efficiencies in the deployment of smart metering cannot be obtained.

The South Australian Government states that the smart meter installation process currently has several inefficiencies and barriers impacting the successful completion of meter installation attempts. [39] Many stakeholders highlight inefficiencies in physically installing smart meters and coordinating smart meter exchanges throughout our consultations. The ETU considered:[40]

> The regulatory framework is driving deep inefficiencies in the way work is performed. Lower skilled workers are less productive and the fragmented contracting out model means sites are often visited several times unnecessarily.

2.3.4 Incentives for individual households are not necessarily aligned with the greater good

Individual households can directly benefit from smart meters, including:

- **enabling CER** – such as solar PV systems, home batteries and electric vehicles (EVs)
- **providing consumers with visibility and control of their electricity consumption and costs** – such as reduced estimated meter reads, better visibility of consumption, and more access and pricing options[41]
- **improving safety outcomes** – such as detection of neutral integrity, which can cause electrocution and 'tingles', and hot joints, which can cause fires.

Smart meters also create indirect, significant system-wide benefits to households – including benefits to DNSPs, retailers and the system operator, AEMO.

For example, DNSPs benefit from smart meters providing improved network operation, investment, security and reliability – such as better outage and LV network management. DNSPs need to operate their networks more dynamically to manage increasing uptake of CER. Their ability to integrate CER and maintain the security and reliability of the grid is hampered by their current lack of visibility of the LV parts of their network. Smart meter data enables DNSPs to make better investment and operational decisions that could support more CER connections and potentially delay or remove the need for augmentation. Access to data from meters could also improve outage management.

39 South Australian Government submission to Directions Paper, p. 5.

40 ETU submission to Directions Paper, p. 4.

41 CEC submitted "Consumers are paying for the smart meter deployment without realising the smart meter benefits. Smart meters can be beneficial but unless the data is accessible there is insufficient value for consumers. The potential benefits of smart meters have not been realised due to difficulties with accessing the data. The data is not made available to customers or their representatives in a useable form." (p. 1)

Individuals will not necessarily consider these broader system-wide benefits when deciding whether to request a smart meter for themselves. They will put more weight on the direct benefits – which may not be compelling for non-CER customers, given the limited retailer real-time data service offerings like the Aurora+ app. This may lead to inefficient levels of take-up of smart meters. All consumers benefit from a more efficient and lower-cost energy system – regardless of whether individuals choose new service options enabled by smart meters.

In the Commission's view, this means there is a strong case for regulatory intervention on behalf of the broader community to realise the broader social benefits – consistent with the long term interests of consumers.

2.4 The need for an accelerated deployment is supported by an independent cost-benefit analysis

The Commission engaged an independent expert consultant, Oakley Greenwood, to undertake an economic cost-benefit assessment of accelerating the deployment of smart meters across the NEM (excluding Victoria and Tasmania).[42] The report is available on the project web page at: aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services.

The assessment considered the economic costs and benefits of an accelerated deployment of smart meters targeting 2030 in place of existing accumulation meters.[43] Oakley Greenwood did not consider the allocation of costs and benefits between different parties – these are financial transfers.

Oakley Greenwood found the overall benefits of an accelerated deployment are greater than the costs (in NPV terms, 2022) for New South Wales and the Australian Capital Territory ($256 million), Queensland ($197 million) and, South Australia ($53.7 million).[44] This finding holds even based on only a limited set of 'non-contingent benefits' that are highly achievable, including benefits derived from:

- reduced costs for routine meter readings and special reads
- the reduction in meter installation costs due to the scale economies of undertaking the deployment geographically
- the ability to de-energise and re-energise the premise remotely (though this feature may not be possible in all jurisdictions).

A more detailed summary of the Oakley Greenwood cost-benefit assessment is provided in appendix F— including the underlying assumptions applied by Oakley Greenwood, and the Commission's further consideration of the timing of costs and benefits under an accelerated deployment, and the implications for retailers and customers.

42 Victoria previously mandated the deployment of smart meters. Tasmania more recently mandated that all accumulation meters are to be replaced by 2026.

43 As compared to the current 'new and replacement' policy in which smart meters are installed when an accumulation meter fails, or when a new meter is needed due to new construction or significant renovation.

44 Oakley Greenwood, Costs and Benefits of Accelerating the Roll out of Smart Meters report, pp. 2, 14-16.

3 A PACKAGE OF REFORMS TO ENABLE ACCELERATED SMART METER DEPLOYMENT

Chapter 2 explains why the Commission recommends the target of universal uptake of smart meters by 2030 in NEM jurisdictions – including our vision for the crucial role smart meters play in the future, and identifying problems with the metering framework that have created inefficiencies and delays under the current deployment program.

The Commission makes 20 recommendations to achieve the 2030 target and to support the efficient deployment of smart meters to the benefit of all consumers. This includes new measures to improve the customer experience and support customers through the transition.

This Chapter provides a summary list of these recommendations – highlighting the mechanisms to implement the proposed changes, with cross-references to the relevant appendices in the report. The appendices following this chapter outline in detail the key issues, stakeholder views, the basis for our recommendations, as well as further consultation questions to guide stakeholder submissions.

Table 3.1: **Metering Review Draft recommendations and positions**

ITEM NUMBER AND LOCATION IN THE DRAFT REPORT	DRAFT RECOMMENDATION OR POSITION	IMPLEMENTATION CONSIDERATIONS
Setting a target and mechanism for the accelerated smart meter deployment		
1 (appendix A.3)	**Accelerate the smart meter deployment to be complete in 2030** There is an economic opportunity to accelerate the smart meter deployment so that it completes by 2030. This timeframe is likely to be the earliest time that is realistically achievable by the industry while maintaining an affordable and reliable energy system.	Acceleration target or targets could be set through the national rules or jurisdictional framework for a recommendation in the Final Report.
2 (appendix A.3)	**Accelerate the smart meter deployment to target 100 per cent uptake** The Commission recommends the target of universal uptake	Same as above

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	of smart meters by 2030 in NEM jurisdictions. This applies mainly to New South Wales, the Australian Capital Territory, Queensland, and South Australia. Victoria has already achieved universal uptake of smart meters, and Tasmania is well on its way.	
3 (appendix A.6)	**Utilise legacy meter retirement plans as a mechanism to accelerate** The Commission recommends adopting a legacy meter retirement approach under an industry-developed plan coordinated initially by DNSPs, to accelerate the deployment of smart meters to achieve universal uptake by 2030. The plan would include regular milestones (e.g., yearly targets) and retailers and metering parties would be required to complete the replacement within a set timeframe.	DNSPs would be required to engage with key stakeholders such as retailers, metering parties and jurisdictional governments to develop and publish their plan per a set of principles. The AER would be required to assess and approve the plan before the acceleration period. DNSPs would then retire legacy meters per the plan, which requires retailers to replace the national metering identifiers (NMIs) within 12 months of the meters' retirement. The AER would be obliged to check compliance with the timeframes through the current retailer performance reporting process.
4	**No change to the current industry structure** The Commission recommends no changes to the current industry structure.	No changes to the national regulatory framework required.

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	Retailers and metering parties will remain responsible for metering services for small customers. The recommendations in this draft report seek to enhance the existing metering arrangements and improve coordination between market participants. They also build on the facilitation of commercial and consumer investment in metering technology to support demand-side participation, including unforeseen outcomes of competitive innovation.	
Reducing barriers to make deploying smart meters easier		
5 (appendix B.1)	**Removing retailer-led deployment opt-out provision** The Commission recommends the removal of provisions enabling customers to opt-out of a retailer-led deployment under standard retail contracts. Retaining an opt-out provision for retailer-led deployments is inconsistent with the broader policy direction of accelerating deployment and would create confusion.	Delete NERR clause 59A(3)(a) allowing small customers to opt-out.
6 (appendix B.1)	**Do not include an explicit opt-out provision under the accelerated deployment**	Seeking stakeholder's views on the removal of the option to disable remote access under acceleration (see

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	As part of the metering review package of reforms, the Commission has considered vital risks that could materially impact consumers, consumer outcomes, and the success of the Review's objectives. The Commission recommends that direct provisions to allowing customers to opt-out of an accelerated deployment should not be added to the regulatory framework.	appendix B.1.6).
7 (appendix B.2)	**Reduce the number of retail notices** The Commission recommends that retailers only provide one notice for a retailer-led deployment This would reduce administrative burden and costs, and enable greater flexibility, planning and coordination – likely without customer impacts.	Delete NERR 59A(2)(b) so the retailer must give one notice to the customer.
8 (Appendix B.3)	**Remove requirements for the testing and inspection of legacy meters** The Commission recommends exempting regular testing and inspection requirements for the legacy meter fleet once the AER approves the legacy meter retirement plan. The risks are lower given that the remaining legacy meter fleet would be retired and replaced	New transitional provision related to Schedule 7.6 that, to avoid doubt, removes the need to test type 5 and type 6 meters if there is a retirement Plan in place for that local network area.

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	throughout the acceleration period.	
9 (appendix B.4)	**Consider a process to encourage customers to remediate site defects and track sites that need remediation** The Commission proposes implementing a customer notification and record-keeping process applicable for circumstances where MC encounter customer site defects. Better-defined arrangements are needed, especially for the accelerated deployment of smart meters.	New provisions in Chapter 7 oblige MCs to provide a defect notice upon discovering customer-side defects. New obligation on retailers to send one notice requesting the customer to remediate after two months and a second notice two months after. Upon two unsuccessful notices, the retailer discounts that NMI from the deployment, and records site information in MSATS.
10 (appendix B.4.5)	**Consider arrangements to better support vulnerable customers who need to carry out site remediation** The Commission proposes that funding support for vulnerable customers who need to carry out site remediation should be considered. Vulnerable customers not having access to smart meters has efficiency and equity impacts.	Coordinate with relevant governments and jurisdictional frameworks – because these are best placed to implement arrangements to help support customers in undertaking remediation and consider the smart meter deployment's broader social and equity considerations.
11 (appendix B.5)	**Improve industry coordination and minimising negative customer impacts in shared fusing** The Commission recommends further developing and using	New installation scenario in Chapter 7 when a supply interruption to replace one meter affects the supply to multiple customers this scenario applies. Outline the process,

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	a 'one-in-all-in' approach to meter replacements to improve meter replacement efficiency and the customer experience in scenarios where meters for customers on a shared fuse need to be replaced.	timeframes, and responsibilities of participants in the Rule.
Improving the customer experience when they get a smart meter		
12 (appendix C.1) (Appendix G)	**Require retailers to provide important information in a clear, streamlined, and consistent way to small customers before any smart meter upgrade** The Commission recommends new obligations for providing up-front and customer-friendly information to customers to support the deployment of smart meters and empower customers to make the best of their meter upgrades under all meter deployments. Evidence from the Newgate research shows many customers were not provided information on how to make the most of their smart meter installed. Some were unaware they could access an app or portal to gain greater insight into their electricity usage. Under this measure, retailers would also be required to inform customers about any up-front costs and changes to	Amend NERR Rule 59C to require retailers to provide information to customers of all types of meter deployments. Outline the line items in the information notice and the timeframes required. The information notice could be sent with the Planned Interruption Notice under rule 59C of the NERR.

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	a customer's retail offering resulting from the meter exchange. This safeguard would help address the risks of customers facing higher costs in the short term before the longer-term benefits of accelerated deployment are realised.	
13 (appendix C.1.6)	**Develop a 'primary-source' smart energy website to enable consistent and customer-friendly information** The Commission proposes that a known and trusted authority should develop a smart energy website to enable consistent and customer-friendly information to be delivered to customers. The website should detail why we need to accelerate the deployment of smart meters and the role of the smart meter in the energy transition — ultimately detailing what it means for consumers.	Oblige a party to develop and operate a smart energy website for the smart meter deployment. Coordinate with the party on the minimum content required and further implementation considerations.
14 (appendix C.2)	**Allow for and accept customer's requests for a smart meter from the retailer for any reason** The Commission recommends that customers should be able to request a smart meter for any reason, for the avoidance of doubt.	Insert a new provision in the NERR that enables small customers to request a smart meter from their retailer for any reason. Require retailers to install a smart upon such a request.

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	The current framework does not specify that a retailer must install a smart meter at a premise upon a customer's request. Although this is common practice, we seek to clarify in the regulatory framework that customers can request and receive a smart meter for any reason.	
15 (appendix C.3)	**Implement appropriate replacement timeframes for meter malfunctions** The Commission recommends a longer replacement timeframe for family failures than for individually identified malfunctions. Separate timelines for individual and 'family' failures of meters are needed to reflect the different nature of the failures and the resources required by the metering parties to undertake the replacements in each case.	Insert a category to NER 7.8.10 of 'individually identified' malfunctions that must be replaced by the MC within a timeframe. Also in NER 7.8.10, insert a category of 'family failures' identified through statistical testing, to be replaced by a longer timeframe.
16 (appendix C.3.6)	**Removing the malfunctions exemptions process currently administered by AEMO** The Commission recommends improving compliance with the timeframe requirements for replacing malfunctioning meters and preventing a backlog of malfunctioning meters in AEMO's exemption register.	Remove the exemption process for small customers from NER 7.8.10 and replace it with circumstances under which the timeframes do not apply.

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17 (appendix C.4)	**Addressing customer risks from automatic reassignment to a new tariff structure** The accelerated deployment of smart meters could shift more customers to cost-reflective pricing structures sooner. The current network tariff framework allows customers to be automatically reassigned off their existing flat tariff structure when their legacy meter is exchanged. Stakeholders highlighted potential risks to customers of bill shock – consistent with insights from our customer research. We also propose a consumer safeguard for tariff reassignment upon a meter exchange, including either strengthening the consideration of consumer impact principles or prescribing a new transitional arrangement.	Further explore the risk with stakeholders, seek clarity and agree to the key risk for a recommendation in the Final Report. Refine options for implementation through the Final Report.
Opportunities to unlock further benefits for consumers and other parties		
18 (appendix D.1)	**Implement a power quality data access and exchange framework** The Commission recommends that DNSPs be given a provision to procure power quality data (voltage, current, and power factor) from MCs, which MCs must provide at least once a day in a standard	New definition of "power quality data" in NER Chapter 10. New access provision for DNSPs under NER 7.15.5. New obligation for MCs under NER 7.6.1. Access parties to involve NER clause 7.17.7(f) to exchange

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	format and exchange architecture. DNSPs can also procure additional services, like a multi-meter ping or data enquiry. We propose that prices would be determined commercially. 'Advanced' services would also be commercially determined, based on a Pro Forma basis.	data directly. Testing with relevant stakeholders in the Final Report who else besides DNSPs could be given access to these data services, with a full-spectrum access framework being ideal.
19 (appendix D.2)	**Enable innovations in access to (near) real-time data** The Commission proposes that customers should be able to accessreal-time data sooner. We have considered two potential service pathways: remote access or local access to real-time data. Real-time data is an expected future service enabled by a critical mass of smart meters; however, its benefits depend on interactions with other reforms that are being implemented sooner.	Working with relevant stakeholders to further define options and implementation considerations for the Final Report.
20 (appendix D.3)	**Evaluate consumer's concerns about privacy** Privacy concerns were the second most significant barrier to consumers requesting a meter in the Newgate study. This is an existing risk that may grow under an accelerated deployment – as more	Seeking stakeholder's view of this consumer risk for a recommendation in the Final Report.

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	consumers receive a smart meter sooner. Using the ESB's Consumer risk assessment tool, we could draw a clearer link between the information transparency measures recommended above and market participants' compliance with the privacy principles and policies. To support this, we could actively observe the general risk of privacy throughout the accelerated deployment.	

ABBREVIATIONS

AEMC or the Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BAU	Business as usual
B2B	Business-to-business
CDR	Consumer data right
CEMS	Customer Energy Management System
CER	Consumer Energy Resources
DMO	Default market offer
DNSP	Distribution network service provider
ESB	Energy security board
EV	Electric vehicle
IT	Information technology
JSON	JavaScript Object Notation
LNSP	Local network service provider
LV	Low voltage
MC	Metering coordinator
MFIN	Meter fault and issue notification
MP	Metering provider
MSATS	Market settlement and transfer solutions
NEL	National Electricity Law
NEM	National energy market
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NER	National energy rules
NERR	National energy retail rules
NMI	National metering identifier
NPV	Net present value
PIN	Planned interruption notice
PQD	Power quality data
PV	Photovoltaic
SMP	Shared market protocol
SO	Service order
TIGS	Temporary interruption of group supply

A ACCELERATING THE SMART METER DEPLOYMENT

This appendix outlines the Commission's draft recommendations to improve the pace of the smart meter deployment to better enable the achievement of long-term efficiencies and benefits. Chapter 2 highlighted the case for a faster deployment. This appendix provides further detail and recommendations regarding the level of acceleration that should be targeted, the date at which universal uptake should be reached, and the potential mechanisms developed and considered by the Commission to achieve accelerated deployment of smart meters. It also includes a recap on the need for accelerated deployment and stakeholder feedback on potential approaches to achieving acceleration.

BOX 3: RECOMMENDATIONS TO SUPPORT THE ACCELERATED DEPLOYMENT

To support an acceleration in the deployment of smart meters, the Commission recommends:

1. Establishing an acceleration target of reaching universal uptake of smart meters by the end of 2030. The proposed target balances the need for providing a sufficient level of acceleration while taking practical considerations into account.
2. An approach to support the achievement of the 2030 target by:
   a. requiring DNSPs to develop a legacy meter retirement Plan in collaboration with key stakeholders, including retailers and metering parties; and
   b. requiring retailers and metering parties to replace 'retired' meters within a certain time frame.

A.1 A faster deployment will reduce costs, increase customer options and pave the way for a more renewable grid

As previously outlined in chapter 2, an acceleration in the deployment of smart meters is needed to enable a more efficient and timelier deployment of smart meters. Along with lowering the costs of deployment, a faster transition to smart meters is a key enabler for the development of new services, technologies, operational approaches and regulatory reforms.

Smart meters are foundational to a modern, efficient and decarbonising energy system that can support great levels of CER adoption, future technologies and innovations. As an example, data from smart meters is an important tool for DNSPs to gain better visibility, so that they can plan and operate parts of their distribution network that are becoming increasingly CER-rich. A faster deployment will better support DNSPs in managing and operating their networks in a way that enables more efficient integration of CER.

Customers' access to smart meters affects their ability to access new services, products and technology offerings. To access some retailer offerings, it is a prerequisite for customers to have a smart meter installed. Similarly, to install and connect a rooftop PV system to the network, customers need to also install a smart meter. Several key existing and proposed future regulatory reforms rely on the deployment of smart meters. For example, the transition to cost-reflective network and retail pricing and the proposed reforms to transition towards a two-sided market are contingent on the deployment of smart meters. Accelerated deployment of smart meters will support the market in being able to benefit from these reforms at a faster rate and customers will be better placed to benefit from a wider range of service and technological possibilities.

Apart from the strategic benefits of facilitating the energy transition and improving the options available to customers, a faster and more planned deployment of smart meters will support a more efficient and lower-cost deployment that can deliver greater system and customer benefits. The economic cost-benefit assessment undertaken by Oakley Greenwood shows that accelerating the deployment of smart meters would deliver positive benefits in Queensland, New South Wales (Australian Capital Territory as part of New South Wales) and South Australia.[45] The assessment shows:

- That the benefits of a faster deployment including greater scale efficiencies, reduced manual meter reads and earlier capture of network benefits are likely to outweigh the potential costs of undertaking the investment in smart meters at an earlier date.
- That accelerating the smart meter deployment to achieve universal or universal levels of smart uptake by 2030 would be in the long-term term interest of consumers.
- A strong economic case for the acceleration of the smart meter deployment while only considering the proven and established benefits of smart meters. Taking into account the other strategic and contingent benefits of smart meters to customers and the system further supports the case for an accelerated deployment of smart meters.

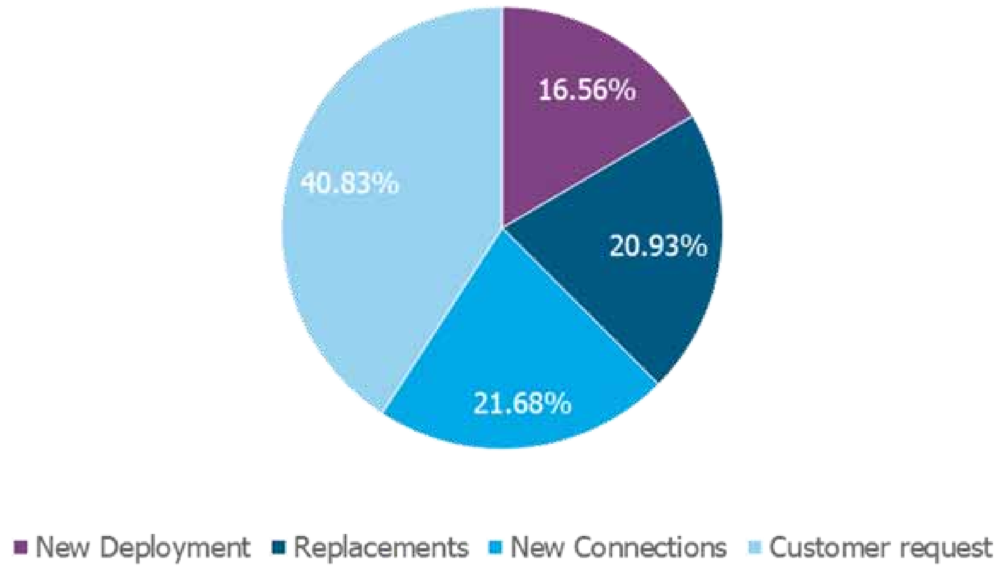
A.2 New measures are needed to support the accelerated deployment

The Commission considers that the current regulatory arrangements are unsuitable for delivering an accelerated deployment of smart meters and that additional regulatory measures are needed to help support a faster and more efficient deployment.

Under the current arrangements, the deployment of smart meters has been largely reactive and slower than expected. The figure below shows the reasons behind the deployment that took place over three financial years. To date, the deployment of smart meters in the NEM has been largely driven by consumers requesting new meters, often as a result of installing solar PV systems, or by new connections. Deployments initiated by retailers have been low in most jurisdictions, with the current framework leading to a piecemeal approach to meter installation and replacement.

45 Only states that do not currently have an accelerated deployment target were considered in the cost-benefit analysis by Oakley Greenwood.

Figure A.1: Reasons for the deployment of smart meters overall

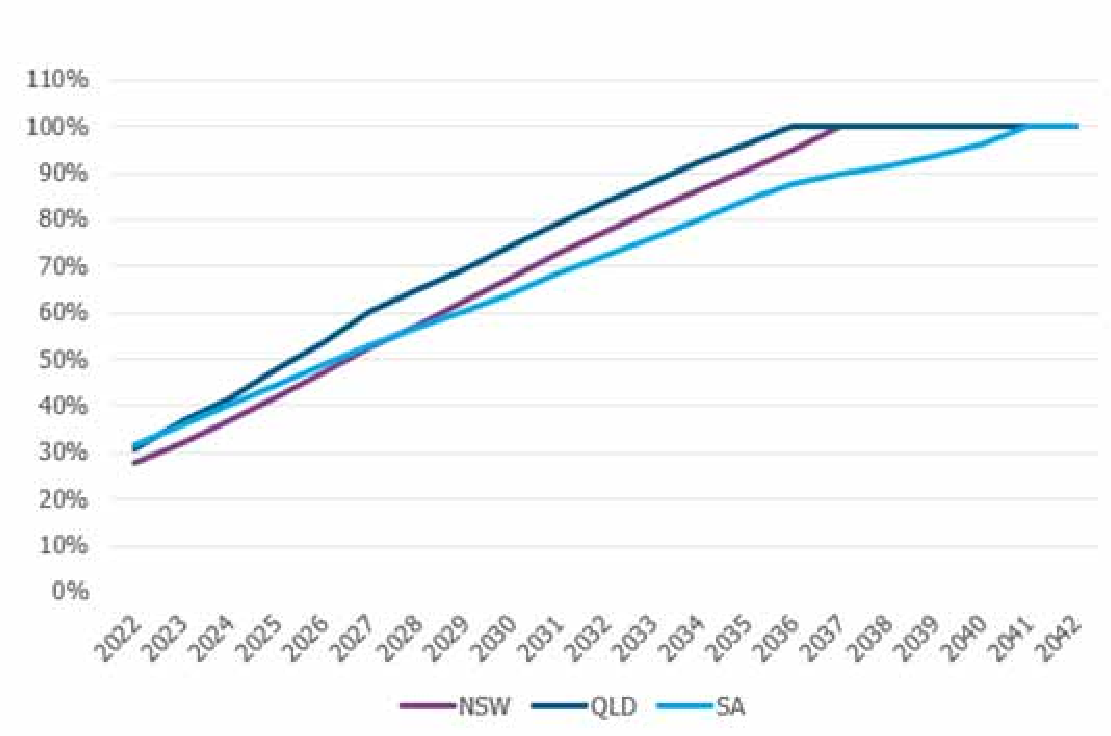


Source: **AER Retail Performance Statistics Q3 2018-19 to Q3 2021-22**

The current arrangements are not expected to deliver a high uptake of smart meters in the near future. As part of the cost benefits assessment undertaken by Oakley Greenwood, the expected future deployment of smart meters under the current arrangements was forecast as part of the BAU scenario. It was found that under the current setting, the uptake of smart meters in New South Wales, Queensland and South Australia is not expected to reach universal or universal levels until 2037, 2036 and 2041, respectively.[46] The forecast deployment under BAU is outlined in the figure below.

46 Oakley Greenwood, *Costs and Benefits of Accelerating the deployment of Smart Meters*, pp. 11-12.

Figure A.2: Forecast of the uptake of smart meters under BAU



Source: AEMC analysis of Oakley Greenwood cost benefit assessment

Accelerating the deployment to achieve universal uptake by 2030 will likely deliver positive net system and customer benefits in all states assessed, as found by Oakley Greenwood.

Although a faster deployment could be possible under the existing framework through increased retailer-led deployments, a voluntary increase in retailer-led deployments cannot be relied upon to deliver a faster deployment. Higher uptake of smart meters achieved in jurisdictions, such as Victoria and Tasmania, was underpinned by a directive or a regulatory mandate to upgrade existing meters to smart meters.

The Commission, therefore, considers that regulatory measures are necessary to facilitate an accelerated deployment of smart meters. The Commission's draft plan to accelerate smart meter deployment contains two key elements:

- achieving a target or targets outlining the desired level of acceleration
- mechanisms or regulatory means to deliver the target.

The acceleration target and mechanism are not meant to be the only means by which to deploy smart meters. The acceleration mechanism will be in addition to the existing types of deployments available under the current framework.

The following sections discuss the two key considerations of the acceleration target and mechanisms for achieving acceleration.

A.3 The Commission recommends the universal uptake of smart meters by 2030

The Commission recommends the target of universal uptake of smart meters by 2030 in NEM jurisdictions.[47] The Commission considers that this timeframe would support improved customer and system benefits, is likely to be achievable by the industry, and facilitates the broader energy transition in a way that maximises net benefits while leveraging scale efficiencies.

A.3.1 Universal uptake by 2030 is expected to maximise net benefits

As highlighted in the Oakley Greenwood study, accelerating the deployment to deliver universal uptake of smart meters by 2030 would maximise net benefits. The study highlights that this level of uptake and acceleration rate can support a more efficient deployment through increased scale efficiencies and an earlier realisation of benefits associated with smart meters, such that, the total benefits outweigh the total costs associated with bringing forward meter replacements.

Delaying the completion date of accelerated deployment beyond 2030 is likely to lead to smaller net benefits due to both higher costs and reduced benefits. The incremental cost of deferring the completion of accelerated deployment to 2032 from 2030 is around $13.5 million, $8 million and $2.1 million for New South Wales, Queensland and South Australia, respectively in NPV terms, as provided by the Oakley Greenwood study. This is because, despite improvement in NPV from reduced smart meter installation costs and capital costs, it would be outweighed by a significant reduction in benefits associated with meter reading costs and other benefits that are assumed to accrue in proportion to the accelerated deployment.

In addition, a completion goal of 2030 for reaching universal uptake of smart meters is likely to be feasible based on analysis by Oakley Greenwood and analysis of the AER retail energy market performance update. Oakley Greenwood observed that the highest number of smart meters that would be deployed (per quarter) under acceleration, to reach a 2030 target, is expected to occur between 2027 and 2028. The accelerated volume of which is expected to be close to double (approx. 104,000 smart meters) of what is deployed under BAU (approx. 53,000 smart meters) in the same period. Analysis of the AER retail energy market performance update for Quarter 3 of 2019-2020 and 2021-2022 indicates that retailers and Meter parties were able to deploy up to 126,000 smart meters in a quarter in 2020-2121, which is higher than the expected deployment volume under acceleration.[48]

It will be important that any set target for acceleration can be reasonably delivered by the parties involved. The ability of the metering industry to be able to scale up to deliver the additional deployments required under the target needs to be considered. An earlier completion date would mean that the metering parties need to scale up and down more

47 Submission to Directions Paper: Origin, p. 3; PLUS ES, pp. 8-9; Ausgrid, pp. 2-4.

48 AER, *Retail energy market performance update for Quarter 3 2019-20* to *Quarter 3, 2021-22*, July 2020 to June 2022, available here.

rapidly, which may impact the efficient deployment of smart meters. It would also mean retailers would face a quicker rise in the costs associated with smart metering.

Stakeholders generally believed it is feasible to reach universal uptake by 2030

Feedback from stakeholders generally suggests that the metering industry is well positioned to be able to scale up to deliver the additional deployments required under a 2030 target as the Commission sought feedback on the feasibility of this target through reference group meetings. In a meeting comprised of all relevant stakeholder groups, almost 60 per cent of participants believed that universal uptake of smart meters through accelerated deployment could be achieved by 2029-2030. This is 45 per cent higher than the voting rate for an earlier target of 2025, which was the second-highest voting rate with 14 per cent. Less than 10 per cent of participants voted for a target beyond 2030. Metering parties and a few retailers consider generally noted that site defects will need to be carefully managed and an early target would likely significantly increase deployment costs compared to the current rate of smart meter deployment with that required under a 2030 target.

There may be roadblocks along the way of reaching a 2030 target

While the goal of an acceleration program should be universal uptake, the Commission is cognisant that this may not be achievable in practice. Metering coordinators can face barriers in undertaking successful meter replacement that can leave a proportion of upgrades unable to be completed. Metering parties could face barriers such as defects in customers' electrical installations, difficulty in gaining access, and customer refusals. Notwithstanding the measures proposed by the Commission to encourage customers to undertake remediation of site defects, there could be a proportion of small customer sites where barriers persist. This has also been the experience in other jurisdictions where some of the more challenging sites are completed after the originally set target. The target of universal uptake will mean that every small customer either receives a metering upgrade or has an opportunity to have their meter upgraded by 2030. The performance assessment of parties involved in the deployment to deliver the acceleration target may need to be considered to ensure they have taken all reasonable steps to deliver a metering upgrade to the customer.

There are different ways of implementing a universal uptake target

In submissions to the Directions Paper, some stakeholders suggest setting an annual target or interval targets (e.g., uptake of ***X*** per cent over five years and higher uptake of ***Y*** per cent over the next five years) that are greater than a year (e.g., three to five years). This is proposed to provide retailers flexibility in selecting deployment volumes and locations that would allow for an optimal and cost-effective deployment process.[49]

The universal uptake target could be set as an end target or coupled with interim milestones (e.g., 75 per cent by 2027). Both approaches could be feasible, but whether one approach is preferable to another depends on the acceleration mechanism that is used.

49 Submission to Directions Paper: Origin, p. 3; PLUS ES, pp. 8-9; Ausgrid, pp. 2-4.

The universal uptake target could be implemented in different ways. For example, the target could be set in the National Rules framework. Implementation via the Rules would support consistency across jurisdictions and potentially simplify compliance for industry participants. The rule changes required could be undertaken along with other reforms proposed in the Review.

Alternatively, the target could be implemented through jurisdictional frameworks. This could allow a target to be set to better meet jurisdictional circumstances. The Commission seeks stakeholder feedback on the preferred approach to implementing the acceleration target.

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?

A.4 Mixed stakeholder feedback on acceleration options outlined in the Directions Paper

In the Directions Paper, the Commission outlined potential high-level approaches that could be considered in accelerating the deployment of smart meters including improving incentives for rolling out smart meters, requiring age-based replacements of meters, setting targets on retailers to switch a certain percentage of their customer base to smart meters setting backstop dates or dates by which legacy meters must be replaced.

Stakeholder feedback showed mixed preferences with some stakeholders outlining the reasons why certain approaches may be preferable.

Retailers generally have mixed views towards the option of setting targets for the meter deployment under which a retailer (or the responsible party) will be required to replace a certain percentage of their customers' meters with smart meters each year. ActewAGL, AGL, Aurora, Red/Lumo Energy oppose this option as they generally view that it would not be suitable within the current competitive framework.[50] Simply Energy support a retailer target, provided that installation barriers such as remediation issues and the opt-out process are addressed.[51] Many DNSPs and metering parties support this option. Some consider that an advantage of this option is that it could provide forecasting for metering parties that would allow them to effectively plan, manage and resource requirement deployments.[52] PLUS ES and Vector provide that an annual target, or the annual target be segmented into a couple of

50 Submissions to Directions Paper: ActewAGL, pp. 5-6; AGL, pp. 5-6; Red/Lumo Energy, p. 1.

51 Simply Energy submission to the Directions Paper, p. 3.

52 Submission to Directions Paper: Essential Energy, p. 2; Ausgrid, pp. 2-4; Endeavour Energy, p 2; CEC, p. 13; EDMI, p. 3; Solar Analytics, p. 3; Intellihub, p. 5; PLUS ES, pp. 8-9; Vector, p. 3; ENA p. 13.

months, would be required — particularly in conjunction with a backstop date — to ensure retailers provide a consistent work schedule for metering parties to avoid resourcing constraints for meter replacements.[53] ECA indicate this option to be the least preferable option as it could lead to customers facing unexpected upfront costs.[54]

Retailers also have mixed views towards introducing a 'backstop' date or dates by which time all accumulation meters (e.g., 90 per cent of meters are required be smart meters by 2030). ActewAGL, Alinta Energy and Red/Lumo Energy oppose this option while it is supported by AGL, Origin and Simply Energy. Simply Energy support a backstop date if barriers to accelerated deployment are addressed.[55] AGL consider that setting a backstop date that is practical would allow the most flexibility for retailers and metering parties out of all the proposed options, as well as allow retaining of existing commercial agreements.[56] Origin considers that an advantage of this option would provide certainty for metering parties that it could provide an opportunity for commercial renegotiation between retailers and metering parties. Other stakeholders, including DNSPs and metering parties, also support a backstop date.[57]-Most stakeholders support an age-based replacement. [58] A few stakeholders emphasise potentially higher costs from remediation issues at sites with legacy meters.[59] Some stakeholders note some views, considerations and suggestions in developing this option, such as:[60]

- DNSPs to coordinate meter deployments alongside retailers and metering parties. For example, coordinating with metering parties where they share a retailer to target common geographical areas to maximise deployment efficiencies and coordinating with retailers to identify legacy meter fleets that are to be replaced within a network area
- requiring DNSPs to nominate sites to retailers with sufficient lead-time to plan and schedule meter deployments
- developing a similar mechanism to the current Meter Failure Notification, implementing a respective replacement timeframe
- applying different age triggers for replacement across network areas to account for differences in the relative age of legacy meters
- the importance of retailers being informed by DNSPs of the expected retirement schedule of legacy meters to allow for more efficient retailer-led deployments
- impact of accelerated deployment on the recovery of residual capital costs if legacy meters are prematurely replaced.

53 PLUS ES submission to the Directions Paper, pp. 8-9.

54 ECA submission to the Directions Paper, p. 3.

55 Simply Energy submission to the Directions Paper, p. 3.

56 AGL submission to the Directions Paper, p. 6.

57 Submissions to Directions Paper: EDMI, p. 3; Intellihub, p. 2; Essential Energy, p. 2; Ausgrid, pp. 2-4; Endeavour Energy, pp. 2, 9; ENA, p. 13.

58 Submissions to Directions Paper: Ausgrid, pp. 2-4; SAPN, p. 6; ENA, p. 13; EDMI, p. 2; Wattwatchers, p. 9; Intellihub, p. 5; PLUS ES, p. 2; Vector, p. 3; Department for Energy and Mining, South Australia, p. 2; Simply Energy, p. 2; EnergyAustralia, p. 2.

59 Submissions to Directions Paper: QFF, p. 4; Alinta Energy, p. 4; Aurora, p. 2; Origin, p. 3; Simply Energy, p. 2.

60 Submissions to Directions Paper: Augrid, pp. 2-4; Red/Lumo Energy, p. 2; Simply Energy, p. 2; Endeavour Energy, p. 10.

MEA Group and Alinta Energy oppose all acceleration options with the view that they should only be considered as a last resort or that they would lead to undesirable outcomes such as higher costs and worsened remediation issues.[61]

A.5 Four options to accelerate the deployment of smart meters have been developed

Based on stakeholder feedback and engagement, the Commission has identified and assessed four different regulatory mechanisms that could be used to help deliver accelerated deployment of smart meters including under a universal uptake target. The high-level options include:

1. **Legacy meter retirement plan:** retiring legacy (type 5 and 6) meters and replacing them with smart meters under an industry-developed plan. Under this approach, DNSPs would be required to work with key stakeholders such as retailers, metering parties and jurisdictional governments to develop and publish a plan to retire their legacy meter fleet in a transparent and orderly manner to support the universal uptake of smart meters by 2030 (the Plan). The Plan will need to be approved and outline a schedule of meter retirements to meet the target. The AER is likely to be best positioned to provide approval of Plans as an independent market authority and its role as the regulator. Meters will be progressively retired by the DNSPs in accordance with the plan and the retailers would be required to replace the retired legacy meters within a set time frame. Retailers would be required to report on their performance in undertaking meter replacements on a regular basis.
2. **Legacy meter retirement by Rules or Guidelines**: retiring legacy meters and replacing them with smart meters via Rules or Guidelines. This option is similar to option 1 above with the key difference being the mechanism for retiring legacy meters. Under this option, the schedule for the retirement of legacy meters would be outlined either via the Rules or a subordinate instrument developed by either the AER or AEMO. The subsequent regulatory steps would be similar to option 1 with retailers being required to replace the retired meters within a certain time frame and reporting on meter replacement performance.
3. **Retailer target(s):** requiring retailers to reach at least a given level of smart meter uptake in line with the acceleration target. Retailers would undertake additional deployments to deliver on the target and report their meter replacement performance.
4. **MC target(s):** requiring metering parties to reach at least a given level of smart meter uptake. Under this approach, all legacy meters will be deemed to have retired at a given time. Retailers would subsequently be required to appoint an MC within a certain time. Metering parties would also be required to report on their performance against the target.

These options outline the potential regulatory pathways for delivering a universal uptake of smart meters by 2030. In identifying these options, the Commission has taken a broad

61 Submissions to Directions Paper: MEA Group, p. 2; Alinta Energy, p. 4.

approach to identifying the possible pathways to achieve acceleration. These options make use of the existing roles, responsibilities and processes under the current regulatory framework. Option 1 requires DNSPs to play a greater role in facilitating acceleration and along with option 2, is based on the existing processes to replace malfunctioning meters. Option 3 makes use of the existing arrangements for retailer-led deployments. A combination or hybrid of the options could be considered for further development.

As further discussed in the sections below, some of the options have been identified to be generally feasible whereas others either require further development before they could be considered viable for adoption or may not be appropriate under the current metering regulatory arrangements.

The Commission recommends the adoption of the legacy meter retirement Plan approach (option 1) as the mechanism to accelerate the deployment of smart meters to achieve universal uptake of smart meters by 2030. For more details on this recommendation, see appendix A.6.

The Commission is interested in feedback from stakeholders regarding any other potential mechanisms to accelerate the deployment of smart meters that may be viable.

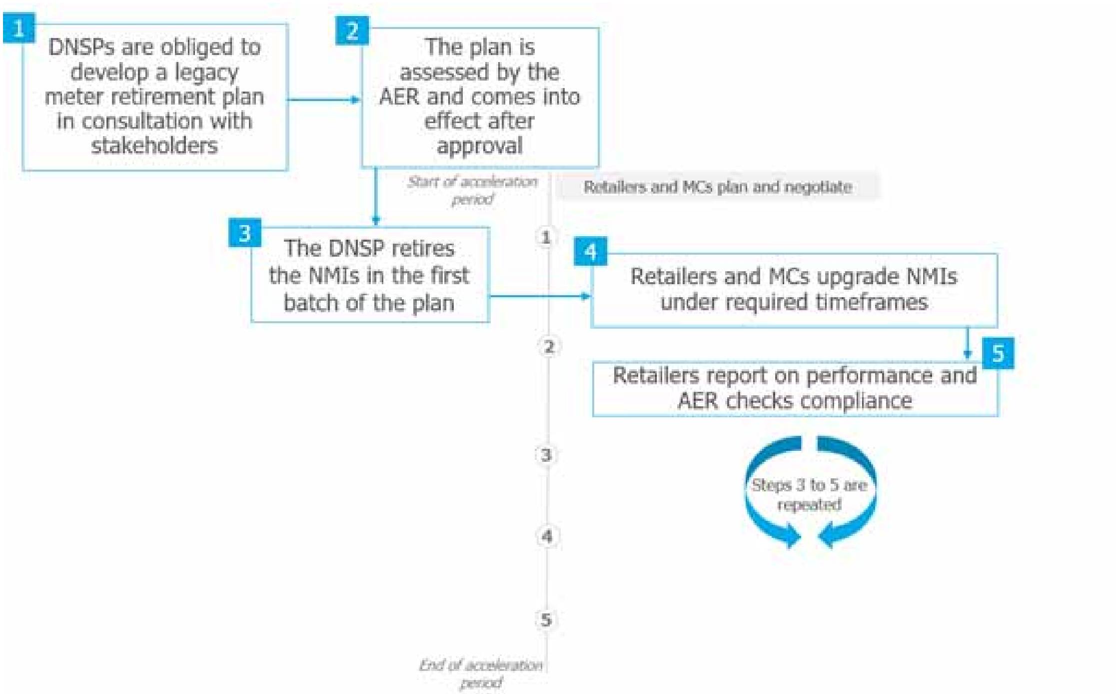
The following sections outline further details regarding each of the four options.

A.5.1 Option 1 — legacy meter retirement Plan

Snapshot of process and roles and responsibilities

Figure A.3 and Table A.1 outline the key steps involved in acceleration under option 1 and the roles and responsibilities of the parties involved.

Figure A.3: Snapshot of the process in a legacy meter retirement Plan



Source: AEMC

Table A.1: Responsibilities of parties involved in a legacy meter retirement Plan

DNSPS	RETAILER AND MC	AER
• Develop the Plan in collaboration with key stakeholders including retailers and metering parties. • Submit the Plan for AER approval.	• Provide input to the DNSP in developing the Plan. • Undertake more detailed planning on meter replacements. • Replace the retired legacy meters in accordance with the schedule in the Plan within a replacement time frame. • retailers to report to the AER on performance.	• Assess the Plan against the principles for approval. • Enforce compliance with Plan and timeline requirements.

Development of the Plan

Under the first step of the proposed process, the DNSP would be required to develop a legacy meter retirement plan that progressively retires their legacy meter fleet to enable the upgrade to smart meters in line with the acceleration target. In developing the Plan, DNSPs would be required to work closely with other key stakeholders such as metering parties, jurisdictional governments and retailers. While DNSPs have the best information about the status and location of legacy meters within their areas, retailers and metering parties are best placed to plan, manage and resource the deployment of smart meters. The Commission considers that it is important for these parties to have strong input in developing the Plan so that the accelerated deployment can be conducted in a structured, efficient and cost-effective manner.

The Plan would set out an annual schedule of meters to be retired each year in order to meet the 2030 target. This approach would provide flexibility for different approaches to be adopted for each network area. For example, key stakeholders may agree to complete the accelerated deployment before the 2030 end date, while others may choose to retire an equal number of meters each year until 2030. The Plan could be revised, amended and resubmitted to the AER for approval on an annual basis or at the discretion of DNSPs in consultation with the other key stakeholders. This would mean adding another administrative and consultation process, which may be time-consuming and costly and could potentially delay reaching the 2030 target. However, it could provide DNSPs and key stakeholders an opportunity to account for changes in circumstances or apply learnings from previous Plans that would allow a schedule in a given period to be feasibly met and/or to be fulfilled in a more efficient and cost-effective manner. A key advantage of this option is that it provides parties involved in the meter replacement process with greater foresight of the forthcoming retirements, thus enabling them to plan and deliver required replacements.

Principles to guide the development of the Plan

Should this option be adopted, the Commission considers that the regulatory framework should include a set of principles to guide the development of the Plan. The principles would provide DNSPs with the flexibility to develop a Plan that suits the circumstances of its network area while providing a consistent policy objective across all jurisdictions.

The Commission has developed an initial set of principles that it considers a legacy meter retirement Plan should meet (see Box 4).

BOX 4: PRINCIPLES TO BE FOLLOWED IN RETIRING LEGACY METERS

1. Be developed with input from key stakeholders, including retailers, metering parties and jurisdictional governments;
2. Retire meters in a manner that enables their efficient replacement. Retirement and replacement of meters based on geography are likely to support an efficient deployment

of smart meters and enable scale efficiencies to be achieved. Other factors like meter age could also be considered;

3. Retire meters in a manner that takes into account the impact on other parties involved in metering. Meters retired under each year of the Plan must be reasonably able to be replaced by the metering party. The Plan may also need to consider the impact on retailers;
4. Support the successful achievement of the acceleration target. The Plan should allow for a reasonably consistent failure rate over time to mitigate delays and inconvenience for customers in the installation process. A retirement schedule that retires a large proportion of the fleet towards the end of the target date may impact the likelihood of the target being achieved; and
5. Outline the required and available information to enable retailers and metering parties to undertake more detailed planning and scheduling of metering works. The information could include the age, type and make of the meter, the likely configuration of the meter board and a high level assessment of whether the site is a multiple-occupation premises or may require remediation work.

Assessment and approval of the Plan

The Commission considers that an independent party, such as the AER, should assess the Plan against the requirement set out in the regulatory framework. The Commission considers the AER is the most appropriate party to conduct this assessment given its experience in assessing proposals from DNSPs.

Retirement of legacy meters

At the third stage, DNSPs will orderly retire the legacy meters according to the Plan and release them in batches annually for replacement. Once the meters have been retired, retailers and metering parties become responsible for their replacement with smart meters. Under this step of the process, retailers would also be required to promptly appoint an MC to replace the meter (a process similar to the current meter malfunction replacement arrangement). While retailers and metering parties have input in deciding the meters to be replaced, it is expected that they would undertake more detailed planning on the approach to replacing them.

Replacement of meters

Under this step, retailers and meter parties will replace the retired meters within a replacement timeframe. The Commission considers a 12-month timeframe balances the need to accelerate smart meter deployment while providing metering parties sufficient time and flexibility to conduct the replacement. This timeframe also aligns with the annual batch release of the retired legacy meters. 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.

If this option is adopted, provisions similar to NER clauses 7.8.10A, 7.8.10B and 7.8.10C is likely to be required

Reporting and compliance

As the last step, it is envisaged that retailers would report on their performance in upgrading the retired meters in the previous period. This could include information on what they were obliged to complete, their success rate and replacements that couldn't be completed due to barriers such as lack of site access and site defects. The existing retailer performance reporting to the AER could be expanded to include requirements to report on performance under acceleration of the deployment.

There are measures in place to enable the AER to enforce compliance with the requirements for installing new meters and replacing malfunctioning meters. The Commission considers that similar arrangements would need to apply for the replacement of retired meters under this option.

The Commission notes that there would be a significant increase to the AER's compliance and enforcement workload under this option. The Commission would work with the AER to develop an appropriate compliance and enforcement regime for accelerated deployment if this option is adopted.

Discussion

The Commission's initial assessment is that option 1 is likely to be viable and feasible to implement. While further work would be required to further develop this option, the Commission has not identified any major barriers to the implementation of this option.

A key feature to note is that while uptake need to develop their Plans to achieve universal smart meter uptake target by 2030, the requirement to have an annual cycle of batch retirement and replacement of meters will essentially lead to yearly targets being in place.

It should also be noted that this option is intended to add to, and not replace existing mechanisms for smart meter deployment. Customers will be able to request a smart meter to be installed, and retailers will still be able to undertake retailer-led deployments. The flexibility to undertake additional retailer-led deployments could enable retailers to undertake deployments in different areas than those proposed under the Plan or at a different scale if that enables better efficiencies or better suits the retailers' needs.

An area of further consideration is whether the arrangements under this option should enable the Plan to be revised. If situations are likely to arise where it may be prudent or necessary to amend the Plan, then the proposed arrangement may provide limited flexibility to promptly amend the Plan. On the other hand, building in regular reviews or adjustments could potentially add additional complexity and regulatory burden. The Commission seeks stakeholder feedback on this approach.

QUESTION 2: LEGACY METER RETIREMENT PLAN (OPTION 1)

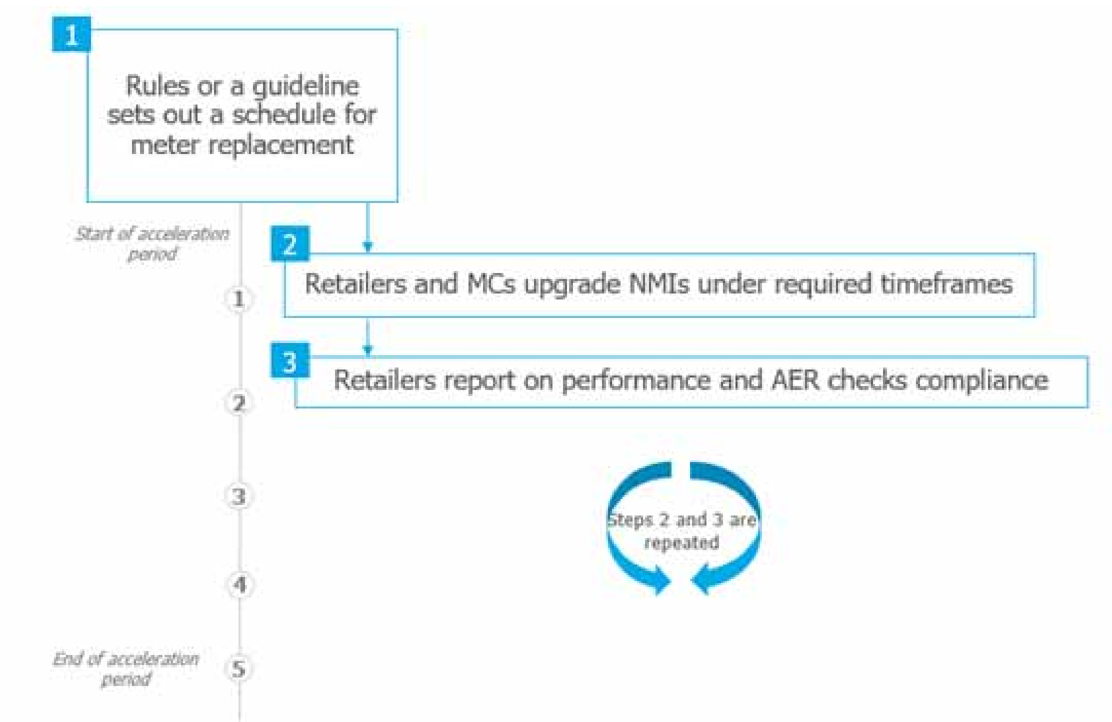
1. Do stakeholders consider this approach feasible and appropriate for accelerating the deployment of smart meters?
2. Do stakeholders consider the Commission's initial principles guiding the development of the Plan appropriate? Are there other principles or considerations that should be included?
3. 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 time frame 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?

A.5.2 Option 2 — Legacy meter retirement through rules or guidelines

The key difference between option 1 and option 2 is that under option 2 the Plan for the retirement of legacy meters would be prescribed in the rules or guidelines instead of an industry-developed Plan. The process and roles and responsibilities for the replacement of legacy is the same as option 1.

Figure A.4 outlines the key steps. Table A.2 outlines the responsibilities of the parties involved.

Figure A.4: Snapshot of the process in a legacy meter retirement through rules or guidelines



Source: AEMC

Table A.2: Responsibilities of parties involved in a legacy meter retirement through rules or guidelines

DNSPS	RETAILERS AND METER-ING PARTY	AEMC, AER OR AEMO
• Engage in the Plan development process and provide the required info to support Plan development.	• Engage in the Plan development process and provide the required info to support Plan development. • Undertake more detailed planning on meter replacements. • Replace the failed legacy meters outlined in the Plan within a replacement time frame. •	• Develop and publish a Plan using information and feedback from stakeholders. • AER to enforce compliance with the Plan and timeline requirements.

DNSPS	RETAILERS AND METERING PARTY	AEMC, AER OR AEMO
	• Retailers to report on performance to the AER.	

Development of the regulatory instrument

The first step in this option will involve a market body developing a schedule in consultation with stakeholders that progressively retires legacy meters to meet the 2030 acceleration target. The schedule will need to cover all NEM jurisdictions (except Victoria) and be consistent with the principles set out in Box 4 above. The market body responsible for developing the Plan is likely to require detailed information regarding each DNSP's legacy metering assets and take into account input from retailers, metering parties and jurisdictional governments to determine the optimal schedule. There are several implementation considerations for this option which are discussed in turn.

Plan detail

Several options are available for the level of detail on legacy meter retirement. The Plan could set the retirement schedule at the jurisdiction, DNSP or regional level. In addition, the Plan could also take into account the age of the metering asset or the needs of a specific part of the network. Similar to option 1, the Plan will also need to set out the frequency of which legacy meters would be retired.

'Location' of the schedule

The Plan for legacy meter retirement could be included as a schedule in the rules. Alternatively, the rules could create a requirement for the AER or AEMO to develop the retirement Plan in consultation with stakeholders. The Commission considers that a guideline or procedure developed by the AER or AEMO is likely to be more appropriate given the significant level of detail required for such a Plan.

Replacement of the meters

Retailers and metering parties will be responsible for the replacement of legacy meters in accordance with the legacy meter retirement schedule. It is also expected that in the lead-up to the retirement of legacy meters, retailers and metering parties would undertake more detailed planning on the approach to replace the upcoming meter retirements.

Retailers and metering parties would still be required to replace the retired meters within a time limit. However, the time frame would be set as part of the rule change or guideline development process.

Reporting and compliance

Retailers would report on their performance against the required meter replacements as part of their annual performance report to the AER. This option would also require the AER to check for compliance with the legacy meter retirement schedule.

Discussion

The Commission's initial assessment is that option 2 is likely to be viable and feasible to implement. This option may also result in yearly targets being in place. Retailers would still have the flexibility to undertake retailer-led deployments.

Compared to option 1, the key benefit of option 2 is that stakeholders would need to engage in a single consultation process as one entity would be responsible for development of a single Plan. A disadvantage of this option is that a significant amount of time would be required to develop the Plan and the responsible market body may not be able to capture requirements specific to all jurisdictions or regions.

A key consideration for this option is whether it would be appropriate and feasible for a market body such as the AEMC, the AER or AEMO to develop a Plan to retire legacy meters. To undertake such activities the market body responsible may need detailed information regarding the legacy meter fleet of each DNSP including information such as age, location, shared-fusing status and current retailer for the legacy meter NMIs. The level of planning and consultation required may also be beyond the market body's level of resourcing. DNSPs on the other hand currently own and manage the legacy meter fleet and have significant experience in meter deployments.

> 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?

Regulatory implementation considerations for options 1 and 2

If options 1 and 2 are to be implemented, the following changes are likely to be required:

- a new category of meter replacements for "legacy meter retirements" in the rules.
- a replacement process of legacy meters that have been retired by DNSPs, which would likely be similar to the existing replacement process for meter malfunctions, including timeframes obligations on retailers
- new provisions in the rules to:
  - place an obligation on DNSPs to prepare a legacy meter retirement Plan (option 1), or
  - require the AER or AEMO to issue guidelines or the Commission to develop rules specifying the relevant trigger(s) (option 2).

A.5.3 Option 3 — Retailertarget

Under this option, retailers would be required to replace legacy meters with smart meters for their customers in line with the acceleration target of universal uptake by 2030. An option for implementation could include interim targets in reaching the completion target of 2030. For example, minimum uptake requirements of 75 per cent by 2027, 85 per cent by 2028 and 100 per cent by 2030. DNSPs would not be involved in the planning of replacing legacy meter fleets.

Figure A.5 outlines the key steps. Table A.3 outlines the responsibilities of the parties involved.

Figure A.5: Snapshot of the process in a retailer target

Source: AEMC

Table A.3: Responsibilities of parties involved in a retailer target

DNSP	RETAILER AND METERING PARTIES	AER OR AEMO
N/A	• Undertake planning on meter replacements. • Replace legacy meters to meet the minimum uptake requirements. • Retailers to report on performance to the AER.	• Develop a guideline outlining approaches to consider the impacts of retail market dynamics on retailer targets. • Assess the retailers' performance report against the minimum target.

Setting requirements for retailers

Under the first step, obligations would be placed on retailers to take all reasonable steps to achieve the smart meter uptake by 2030, and interim targets if they are set. There are two potential implementation pathways for this option:

- **Target-based approach**: under this approach, the rules or a guideline would set the high-level target (universal uptake by 2030 or more granular or interim targets). For example, minimum uptake requirements of 75 per cent by 2027, 85 per cent by 2028 and

100 per cent by 2030. Retailers and metering parties would have the flexibility to determine how the deployment is conducted.

- **More prescriptive approach:** under this approach, retailers would be required to develop a deployment plan outlining their approach to achieve the target(s) that are set out in the rules or a guideline. Retailers' plan would need to outline their approach to addressing market dynamics and exogenous factors that could affect its performance against the target.

Meter replacements

Retailers or metering parties would then undertake meter deployments to ensure compliance with the relevant requirements. It is expected that retailers would be able to use the existing provisions allowing them to undertake retailer-led deployments.

Reporting on performance and checking compliance

Like under options 1 and 2, retailers would report on their compliance with, and performance against, the meter deployment plan to the AER. In determining a retailer's performance, the AER would need to take into consideration the impact of sites that could not be upgraded due to external factors such as site defects, customer refusal and lack of access.

Discussion

The Commission considers that this option is likely to be feasible to deliver the acceleration target. However, the Commission's initial view is that there are complex issues that need to be addressed to progress this option further before it could be considered viable for adoption.

A key issue to consider is the impact of existing market share and retail market dynamics that could have on different retailers. Unlike DNSP customer bases (which are fixed), a retailer's customer portfolio could change over time and can differ from one another due to:

- **Customer churn**: a retailer's performance against an acceleration target could change as a result of customer churn. It could lose customers that already have a smart meter installed while gaining customers that are yet to have their legacy meters replaced. This could lead to situations where a retailer could be deemed non-compliant with the uptake requirements even though it has undertaken its fair share of upgrades throughout the year. It could also lead to an increased burden on retailers who are further along the smart meter journey with a higher uptake rate as they would be more likely to lose customers with smart meters than gain customers with smart meters.
- **Market Entry, Exit and retailer of last resort events**: In situations where a retailer gains customers due to a market of a retailer or due to retailer of last resort events, they could gain a large number of customers at a given time with a different smart uptake rate than their customer base.
- **Different geographic footprints**: Some retailers could have a different geographic presence than others. For example, a retailer with little to no customers in one jurisdiction might be impacted differently under this target when compared to a retailer with a stronger presence.

- **Different starting points**: Some retailers could have a higher uptake of smart meters than others at the start of the acceleration period. Interim uptake targets that are based on the starting point of the average market uptake rate may impact retailers differently.

These issues mean that a retailer's performance against its target may change due to events outside of its control and the impact of these factors will need to be considered in setting appropriate targets for retailers and assessing compliance. If this option is adopted, the Commission considers that further guidance will need to be developed to take into account factors that affect retailer performance.

QUESTION 4: RETAILER TARGET (OPTION 3)

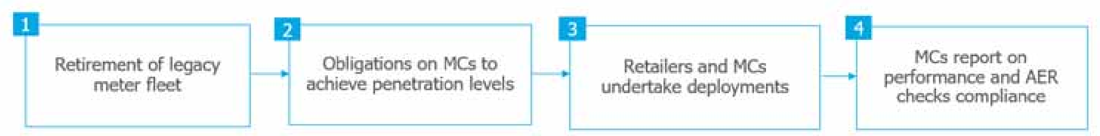
1. Do stakeholders consider option 2 is feasible and appropriate for accelerating the deployment of smart meters? Are there aspects of option 2 that need further consideration?
2. If this option is adopted, what are stakeholders' suggestion on how retail market dynamics could be taken into consideration 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?

A.5.4 Option 4 — Metering Coordinator target

Under this option, the MCs would be responsible for planning and undertaking meter replacement to achieve universal smart meter uptake by 2030.

Figure A.6 outlines the key steps. Table A.4 outlines the responsibilities of the parties involved.

Figure A.6: Snapshot of the process in metering coordinator target



Source: AEMC

Table A.4: Responsibilities of parties involved in a metering coordinator target

DNSP	RETAILER AND METERING PARTY	AER
N/A		

DNSP	RETAILER AND METERING PARTY	AER
	• Undertake planning on meter replacements. • Metering parties to replace legacy meters to meet the meter uptake target. • MCs to report on performance to the AER.	• Develop a guideline outlining approaches to consider the impacts of metering market dynamics on MC targets. • Assess the MCs' performance report against the deployment target.

Mass retirement and MC appointment

The first step of this option would see the retirement of the entire legacy meter fleet. This would most likely need to be triggered through a provision in rules. Once the legacy meter fleet has been retired, retailers would be required to appoint MC(s) for their sites so that the physical replacement can commence.

This step is necessary because unlike retailers under the current framework, MCs cannot initiate meter upgrades on their own and they need to be appointed by a retailer to commence the meter replacement process.

Requirements for MCs

As part of the second step, obligations would be placed on MCs to take all reasonable steps to replace the legacy meters at premises for which they have been appointed the MC. Metering parties will then undertake sufficient metering upgrades to ensure they complete the replacement of their assigned meters by 2030.

Similar to option 3, this option could be implemented as a high-level target only or supported by other measures such as interim targets, a guideline outlining yearly quotas or using a plan developed by the MCs and approved by the AER.

Reporting on performance and checking compliance

MCs would be required to report on their performance to the AER on a regular basis. If only a high level target is set, MCs' report would need to include details such as the number of meters replaced, number of replacements outstanding, and their assessment of the likelihood of completing replacement by 2030. The reporting could also be against interim targets or MC-developed plans where applicable. In determining an MCs performance, the AER would need to taking into consideration the impact of sites that could not be upgraded due to external factors such as site defects, customer refusal and lack of access.

Discussion

The implementation of this option may require more extensive regulatory changes when compared to other options. The Commission considers that this option may not be well aligned with the roles and responsibilities under the metering framework and there are a number of challenges for MCs to be able to meet their obligations effectively and efficiently.

This option also introduces additional complexities. While MCs are responsible for performing metering functions, the responsibility for metering services and contractual relationship with the customer remains with the retailer. Under this option, while MCs would be responsible for meeting the uptake target, they are still dependent on retailers to appoint them before they commence replacement work. Further retailers would remain responsible for most of the customer-facing aspects of the upgrades such as scheduling replacement times with customers and notifying the customer.

Option 4 could lead to MCs being held accountable for upgrades despite not having full control or the ability to deliver upgrades on their own. Therefore, option 4 could lead to MCs being held responsible for performance with respect to the acceleration target while their ability to deliver on the target would depend on the actions of other parties.

Like option 3, option 4 could also be impacted by the dynamics of the market. The issue of churn could also affect MCs as well. Retailers appoint MCs for their customers under commercial agreements, and they can change their MC for a site especially if the meter upgrade hasn't taken place. The number of sites that an MC has responsibility for could also change depending on agreements struck with retailers. For example, an MC could win a large contract from a retailer part-way through the acceleration period. This could impact the MC's ability to meet its required target. Similarly, to option 3, market entry or exit in the competitive metering industry could also impact the ability of MCs to upgrade meters.

A.6 Legacy meter retirement approach should be adopted to accelerate the deployment of smart meters

The Commission recommends the adoption of the legacy meter retirement Plan approach (option 1) as the mechanism to accelerate the deployment of smart meters to achieve universal uptake of smart meters by 2030. The setting of regular milestones through yearly targets and compliance checks is more likely to enable successful acceleration in smart meter deployment.

The requirement for DNSPs to develop the Plan with input from key stakeholders would also support greater buy-in from stakeholders and thereby increase the chance of success. The collaborative development of the Plan will allow for the inputs from all key stakeholders to be considered and the flexibility in the approach to the development of the Plan can support effective management and the potential impacts on the different parties. This approach could also enable better coordination in the deployment of smart meters as all parties will have visibility and input into the Plan. As an example, under the planned approach, multi-occupancy sites that are likely to have shared fusing could be scheduled to be retired at the same time, supporting coordinated replacement and minimising the impact on customers.

Having a high-level deployment plan at the start of the acceleration period would also provide greater certainty and clarity to the parties involved. For example, metering parties will have visibility of the long-term meter replacement schedule. Using this information and their agreements with retailers they can efficiently scale their operations to deliver the required upgrades each year. With a high-level plan in place, the retailers and metering parties can focus their efforts on planning for the best approach to delivering the overall plan.

An additional efficiency benefit delivered under option 1 is that along with enabling an efficient deployment to achieve scale benefits it could also enable other benefits to be captured more effectively such as those derived through undertaking targeted upgrades in areas that can enable better visibility of LV network for the DNSPs.

Options 3 and 4 are considered not viable for adoption in their current form. Both options would be complex to implement and issues such as customer churn and overlapping responsibilities would need to be considered if these options are to be adopted. Option 4 is considered the least viable approach as it is unlikely to be compatible with the ongoing metering framework arrangements. Further information is also needed regarding the suitability of requiring a market body to develop the retirement and replacement plan under option 2.

A.7 Comparing key features of the options

A.7.1 A single target vs interim targets

Under options 1 and 2, the annual release of legacy meters for retirement under option 1 and 2 will indirectly create interim uptake targets. Whereas for options 3 and 4, could be implemented with one high level target only, or have interim targets set. An approach with a single target (i.e., universal uptake by 2030) could provide the industry with flexibility in how the legacy meters are replaced. However, the Commission considers that an approach that includes regular interim milestones is likely to be preferable as it would provide better certainty towards the achievement of the acceleration target and enable intervention in a timely manner if needed. It would also support greater consistency in the number of upgrades across the acceleration timeline in a coordinated manner so that a bulk of the upgrades are not scheduled to be delivered in a short time frame, such as, closer to the end of the acceleration period. It could also support a more equitable delivery of smart meters to customers. All the acceleration mechanisms can be designed to deliver interim targets.

A.7.2 Party undertaking the planning of works

A key difference between meter deployments under current arrangements and acceleration would be that accelerated deployments would need to be delivered in a planned and coordinated manner. Under all the mechanisms considered, key stakeholders will determine how meter upgrades will be delivered to customers with legacy meters to achieve the acceleration target. It will be important to consider the parties responsible and involved in the planning of smart meter deployments as some parties may be better positioned to undertake some steps involved in the planning of delivering metering upgrades. The following table outlines the parties responsible for planning under each option.

Table A.5: **Parties responsible for planning in each acceleration option**

	OPTION 1	OPTION 2	OPTION 3	OPTION 4
Parties responsible for the planning of upgrades i.e., deciding the schedule of meter upgrade	DNSPs will coordinate longer-term planning with significant industry input. Retailers and MCs will undertake more detailed planning i.e., within the year.	The responsible market body and Industry will undertake higher-level and longer-term planning. Retailers and metering parties will undertake more detailed planning i.e., within the year.	Retailers and metering parties will undertake planning.	MCs and retailers will undertake planning.

The Commission considers that there are strengths and weaknesses in the different approaches towards planning under the options. For example, retailers and MCs undertaking the planning could provide for greater flexibility in planning and reduce the regulatory burden of developing a replacement plan upfront, such as under options 1 and 2. However, retailers and MCs are unlikely to be able to plan for an efficient replacement on their own as they would require information from DNSPs about the legacy meter fleet. An upfront planning approach to undertaking replacements could also provide greater clarity and certainty and enable better coordination between retailers, MCs and DNSPs.

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?

B REDUCING BARRIERS TO INSTALLING SMART METERS AND IMPROVING INDUSTRY COORDINATION

Stakeholder feedback and the Commission's Directions Paper identified several opportunities to improve smart meter installation processes to enable smoother and faster deployment of smart meters. The Commission found that some existing arrangements were leading to inefficiencies in the deployment of smart meters, and the lack of coordination between parties and defects in customers' sites prevent successful meter upgrades.

This appendix outlines the Commission's draft recommendations to lower the barriers to rolling out smart meters and improve coordination among parties to enable more successful installation of smart meters. These changes would also improve efficiencies and economies of scale to support accelerated deployment to reach universal uptake across the NEM by 2030 and support a better customer experience.

BOX 5: DRAFT RECOMMENDATIONS TO MAKE IT EASIER TO DEPLOY SMART METERS

The Commission's draft recommendations make it easier to deploy smart meters by:

1. Lowering the barriers to deploying smart meters, through:
    a. removing the option for customers to opt-out of a smart meter deployment
    b. reducing the number of notices to be sent to customers by their retailers before a retailer-led deployment from two to one
    c. reducing the testing and inspection requirements for legacy meters
    d. enabling processes to encourage customers to remediate and better track customer sites defects
    e. proposing arrangements to better support vulnerable customers in addressing defect issues preventing metering upgrades.
2. Facilitating better cooperation through:
    a. enabling measures to support improved industry coordination in upgrades meters for customers with shared fusing scenarios via a 'one-in-all-in' approach.

B.1 Customer opt-out could hinder the efficient deployment and benefits of smart meters

The Commission recommends the removal of provisions in the NERR enabling customers to opt-out of a retailer-led deployment under standard retail contracts. The Commission also recommends that the acceleration framework should not include direct provisions to allow customers to opt-out of a programmed deployment.

Retention of the opt-out provisions could lead to customers indirectly incurring metering costs without access to its service offerings that provide direct metering benefits, such as more accurate billing. In addition, it could pose inconsistencies with other reforms, including those to address the multi-occupancy issues.

As part of the package of reforms, the Commission also recommends safeguards and measures to improve customer experience that address concerns regarding smart meter deployment. These measures and flexibility in how the market achieves acceleration should enable a faster deployment in a way that protects customers from possible negative experiences or outcomes.

B.1.1 Some customers can currently opt-out of retailer-led deployments

Rule 59A of the NERR allows customers to opt-out of a retailer-led deployment up to seven business days prior to the intended meter installation date. The Commission introduced this provision as part of the competition in metering rule change as counterbalancing protection for enabling retailers to undertake retailer-led deployments in scenarios where customers' meters were still functional to preserve the option for customers to retain their existing meters.[62]

Rule 59A of the NERR allows customers to opt-out of a retailer-led deployment up to seven business days before the intended meter installation date. The original intent of the opt-out provision was to support consumer confidence in retailer-led deployments, which was at the time preferable to a strictly opt-in model for retailer-led deployments.

Rule 59A(8) exempts retailers from complying with the opt-out provisions if the retailer is authorised to undertake new meter deployments under the terms of their small customer market retail contract. However, this is not permitted for standard retail contracts. Feedback from stakeholders has also highlighted that customers on the vast majority of Retail contracts waive these protections. In the jurisdictions where NECF applies, 78 per cent of the small residential customers are on market contracts.

Customers' ability to opt-out of the programmed deployment will affect consumer choice, efficiency and success of the deployment. It also needs to be considered alongside opt-out of retailer-led deployment.

B.1.2 Most stakeholders support no opt-out

The Commission sought stakeholder feedback in the Directions Paper on whether the provision enabling customer opt-out of retailer-led deployments should be removed. Most stakeholder submissions support removing opt-out because they consider:[63]

- opt-out was a barrier to the efficient deployment of smart meters that offered little consumer protection

62 AEMC, *Competition in Metering rule change final determination,* p. 351.

63 Submissions to the Directions Paper: Ausgrid, p. 3; Endeavour Energy, p. 16; CEC, p. 10; ENA, p. 18; EnergyAustralia, p. 11; Green Metering p. 11; EWON, pp. 6-7; PLUS-ES, pp. 28-29; Origin, p. 7; Solar Analytics, p. 8; MEA, p. 7; PIAC, p. 17.

- allowing opt-out would entrench legacy metering in the network and reduce the economic efficiency of a targeted deployment
- removing this clause would assist in accelerating the smart meter deployments and improve deployment efficiencies.
- removing opt-out would meter replacements at multi-occupancy sites by allowing the replacement of all meters on the panel at once.
- opposition of advanced communications should not be a barrier for the smart meter asset to be installed as customers can request a type-4A metering installation
- all consumers should have equal access to capable metering.

Some stakeholders support removing the opt-out provision granted other safeguards are introduced. It is suggested that vulnerable customers shouldn't be required to pay for expensive remediation of their electrical installation.[64] Other stakeholders suggest that customers receive upfront information about the meter exchange and have the option of remaining on their existing retailer tariff after the metering upgrade.[65]

Some stakeholders prefer retaining the opt-out provisions because they consider that:[66]

- the removal could lead to increased customer complaints and resistance due to the perception of a lack of choice
- in the near term, an incentive-based model would be preferable
- the Commission should address other issues related to smart meter hesitancy before amending customer opt-out rights
- removing opt-out could lead customers to be compelled onto a high-cost metering program.

B.1.3 Commission recommends the removal of the opt-out provision

The Commission recommends:

- the removal of provisions under NERR Rule 59A that allow customers to opt-out of retailer-led deployments
- that provisions enabling customers to opt-out of deployments under the acceleration program shouldn't be introduced

The Commission considers that customer opt-out could lead to inconsistencies and inefficiencies in the deployment of smart meters. Additionally, the Commission's recommendations to improve the customer experience address concerns regarding customer harm in metering exchanges.

Our draft recommendation promotes consistency of approach and harmonisation of customer rights across different metering deployment types.

64 CEC submission to the Directions Paper, p. 10.

65 Submissions to the Directions Paper: ENA, p. 18; Endeavour Energy, p. 17; EWON, pp. 6-7; Bright Spark Power, p. 11; CEC, p. 10.

66 Submissions to the Directions Paper: AGL, p. 17; ECA, p. 5; Red Energy and Lumo Energy, p. 5; Simply Energy, p. 5; Wattwatchers, p. 17.

B.1.4 Opt-out could lead to inefficiencies and inconsistencies

The Commission considers that enabling explicit opt-out provisions would not be appropriate as they could undermine the efficiency of the deployment, create complexities and inconsistencies in the framework and give rise to perverse outcomes for some customers.

Providing explicit provisions for customers to be able to opt-out of retailer-led or programmed smart meter deployment could:

- impact the efficiency of the deployment and jeopardise the level of acceleration and achieving an overall uptake because some customers may choose to opt-out of receiving upgrades
- introduce additional steps in the deployment of smart meters and further complexities to the planning and execution of programmed deployment as there would be a need to account for customers opting out of metering upgrades
- create inconsistencies in the rights of customers because other reforms, including the one-in-all-in approach to address the metering exchanges for customers on a shared fuse, rely to a large extent on no customer opt-out. Enabling opt-out for customers other than those on shared fuse would lead to an inconsistent approach, and customer confusion
- give rise to perverse outcomes, as customers choosing to opt-out of a meter upgrade could still face the costs associated with smart meter deployment as part of their retail charges. However, customers would not access the direct benefits of having a smart meter – an adverse outcome, especially for vulnerable customers.

B.1.5 Measures addressing customer concerns with meter exchanges

The Commission notes concerns regarding a lack of customer choice in receiving a metering upgrade, which could impact customers' ability to manage their concerns related to meter exchanges. However, the Commission considers directly targeting consumer concerns or potential harms in metering exchanges would better address the issue than through a broad and explicit opt-out provision.

As outlined in chapter 3, the Commission proposes to introduce measures to address ongoing customer concerns related to meter exchanges and improve customer experience when they receive a metering upgrade. The Commission expects these new measures, along with some of the existing arrangements, to address reasons that are understood to lead to customers choosing to opt-out. Notable new measures include:

- protections for customers from the automatic reassignment of tariffs coupled with metering exchanges
- up-front provision of information to customers regarding the exchange, their rights to provide customers more certainty and reduce concerns regarding the exchange.

Concerns regarding customers facing high remediation costs are likely to be addressed under the proposed approach for site defects. These recommendations don't oblige customers to undertake remediation while providing sufficient opportunity and information. Vulnerable customers should also be to access financial support to undertake remediation.

Implementation considerations

Notwithstanding these safeguards, the Commission notes that some customers could refuse a metering upgrade for various reasons or not provide appropriate access to enable the metering upgrades to take place. Under such circumstances, obliging a customer to accept a metering upgrade may pose challenges to social licence and customer experience. The Commission considers that such cases are likely to be better addressed by considering how compliance against requirements in the acceleration measures is measured. There is expected to be a small proportion of sites that don't get upgraded due to the reasons mentioned above. Details on proposed changes to the NER are provided in Table C.2xxx in chapter xx (see amendment 4).

> 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?

B.1.6 Removal of the option to disable remote access

Under current arrangements, customers can choose to disable remote access capabilities (e.g. remote meter reads) upon installation.

Under accelerated deployment, this option could lead to inefficiencies and higher metering costs as it would mean site visits by MPs would be required. Oakley Greenwood provided that avoiding having to manually read meters is a significant driver to the results of a positive net benefit for all states from accelerated deployment.[67]

The Commission welcomes feedback on whether customers should continue to have the option to disable remote access capabilities under accelerated deployment.

> 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?

B.2 Retailers only need to provide one notice for retailer-led deployments outlining relevant information for customers

As initially proposed in the Directions Paper, the Commission recommends reducing the number of notices a retailer provides a small customer when undertaking retailed led

67 Oakley Greenwood notes that for Queensland, the net benefit of accelerated deployment remains positive with the removal of benefits of remote disconnection and reconnection.

deployments under rule 59A – from two notices to one. This notice requirement would be the same as the proposed smart meter information notice requirements.

B.2.1 Strong stakeholder support for a reduced number of notices

Stakeholders strongly support that the preliminary recommendation in the Directions Paper would improve installation efficiencies. They note several benefits in their submissions, including:[68]

- reduced administrative burden and costs
- improve the efficiency of smart meter deployment by enabling greater flexibility, planning and coordination
- providing greater flexibility to retailers with negligible impact on customers, and
- enabling better planning and coordination, providing for overall improvement in deployment efficiencies.

B.2.2 Streamlined notifications requirements to improve customer experience

The Commission considers that reducing the number of notices required and enhancing the information necessary in notices would lead to a more efficient process for deploying smart meters and improved customer experience.

It can reduce customer confusion and regulatory burden by reducing the duplication of information provision for retailer-led deployments. It will also promote consistency of information provision for all metering installation types and simplify arrangements.

Appendix C.1 outlines the details of the streamlined information requirements. Under the proposed smart meter information notice requirements, the retailers must send a single notice to small customers not more than 60 business days and not less than 15 business days before the proposed meter installation date for any deployment type.

B.3 Reduced testing and inspection requirements for legacy meters

The Commission recommends an exemption from regular testing and inspection requirements for the legacy meter fleet (type 5 and 6) once they are retired under their Plans (as approved by the AER) or by Rules or Guidelines, provided either of these acceleration measures are implemented (see Appendix A).

Assuming the Commission's preferred acceleration measure (the legacy meter retirement plan) is implemented, the Commission recommends introducing a transitional rule related to NER Schedule 7.6. This transitional rule would remove the testing requirements for DNSPs who are MCs for type 5 and 6 meters under NER 11.86.7(a) if the DNSP has Retirement Plan approved by the AER.

68 Submissions to the Directions Paper: Alinta Energy, p. 9; ENA, p. 18; Simply Energy, p. 1; PIAC, p. 17; AGL, p. 17; AEC, p. 8; MEA Group, p. 4; Red Energy and Lumo Energy, p. 4; Bright Spark Power, p. 81; EnergyAustralia, p. 2; CEC, p. 10; Green Metering, p. 11; EDMI, p. 7; Telstra, p. 4, PLUS ES, p. 27; Vector, p. 18, Aurora, p. 4.

Considering the programmed deployment of smart meters, the Commission finds that the Rules should consider testing and inspection requirements and replacement time frames for family failures separately for smart meters and legacy meters. The removal of testing and inspection requirements of legacy meters could be appropriate given that the remaining legacy meter fleet would be retired and replaced throughout the acceleration period. Inspecting and testing meters about to be replaced may add cost burdens above the potential benefits. It could also reduce the complexities involved in planning the accelerated deployment and development of the legacy meter retirement plan.

This recommendation also means there will be limited numbers of legacy meter family failures in the future. This should help simplify the planning required to deploy smart meters as it would reduce the uncertainty in the number of meters to replace at any given time. The inspection and testing requirements should continue to apply to smart meters (type 4S and 4A) as per current arrangements. For replacement time frames for malfunctions, see appendix C.3.

The Commission seeks stakeholders' views on the merits of removing testing and inspection requirements for legacy meters.

B.4 Supporting greater success in installations for sites with defects

Site defects present a significant barrier to the successful installation of smart meters. To promote more significant levels of site remediation by customers and more equitable deployment of smart meters, the Commission recommends:

- the development and adoption of a process to encourage customers to remediate site defects and enable record keeping of customer site defects
- customers to remain responsible for remediating sites
- governments consider arrangements, including financial support for customers to undertake site remediation.

B.4.1 Site defects are a barrier to successful metering upgrades

As highlighted in the Directions Paper, defects in the customer's electrical installations can often prevent metering installations. Common defects include the insufficient size and poor condition of the meter panel, poor conditions of wiring in the board and asbestos in the panel.

In most jurisdictions, customers are responsible for undertaking remediation to provide a site capable of accepting metering upgrades. Metering parties and retailers are not able to oblige the customer to undertake remediation, and particular groups of customers may not be in a position to readily remediate, such as customers in social housing and of low income.[69]

Site defects will likely impact the accelerated deployment of smart meters as they limit the level of smart meter uptake that could be successfully achieved under the acceleration program and affect the efficient deployment of smart meters. Often, customers or service

69 The Commission is aware that some retailers fund minor remedial works to enable metering upgrades to progress.

providers don't undertake the remedial work required to enable meter replacements. Site defects result in the abandonment of meter replacements and place unexpected costs and delays on the customer. Site defects can also impact the efficient deployment of smart meters because the current arrangements don't support efficient management and transparency of site defects.

The Commission considers that financial barriers are a key reason for customers not undertaking remediation. To remediate the site defects, customers face the upfront costs of engaging an electrical contractor, which can be significant. Customers also face little incentive to undertake remediation as the direct benefits of undertaking remediation can be limited in some circumstances.

B.4.2 Stakeholders urged site remediation issues to be progressed while noting limitations of the national framework

Many stakeholders convey in submissions to the Directions Paper that addressing site remediation issues should support successful meter deployments, noting some suggestions for the source of funding. Submissions included funding via a sinking fund, network charges and/or government subsidies.

Some retailers and metering parties saw merit in establishing a sinking fund and sharing costs across the customer base via network charges.[70] DNSPs generally note they are not best placed to remediate sites as it would not be within their remit under specific jurisdictional schemes, and they are no longer responsible for meter installations.[71] EnergyAustralia believes it would not be equitable to smear remediation costs across customers.[72] Some consumer groups view that consumers should not be facing upfront costs for remediation that may be required.[73]

Many stakeholders note limitations in the national framework to support funding and highlighted the need to provide support for vulnerable customers for an equitable meter deployment.[74] Some of these stakeholders and those in Reference group meetings consider government(s) to be best placed to provide support, particularly for vulnerable customers.[75]

70 Submissions to Directions Paper: PLUS ES, p. 26; Intellihub, p. 12; Vector, p. 18; Simply Energy, p. 2; Red Energy and Lumo Energy, p. 4.

71 Submissions to Directions Paper: Ausgrid, p. 4; ENA, pp. 17-18.

72 EnergyAustralia submission to the Directions Paper, p. 1.

73 Submissions to Directions Paper: PIAC, p, 16; ACOSS et al., p. 7.

74 Submissions to Directions Paper: PLUS ES, p. 26; Intellihub, p. 12; Vector, p. 18; ENA, p. 18; ACOSS, p. 6; PIAC, pp. 15-16; CEC, pp. 9-10.

75 Submissions to Directions Paper: ENA, pp. 17-18; PLUS ES, p. 26; Intellihub, p. 12; ECA, p. 2; AGL, p. 7; Alinta Energy, p. 9; Bright Spark Power, p. 8; ReAmped, p. 1; Endeavour Energy, p. 18.

B.4.3 Development and adoption of a process to encourage customers to remediate site defects and enable record keeping of customer site defects

Process for handling customer site defects

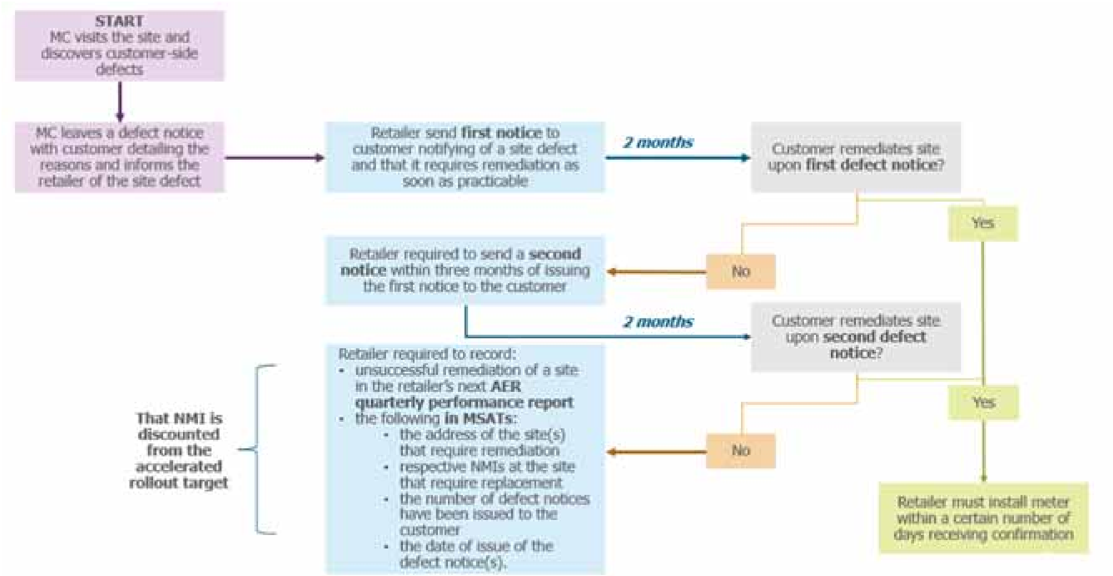
The Commission proposes implementing a customer notification and record-keeping process applicable for circumstances where customer site defects are encountered (see Figure B.1). It is suggested that these arrangements will apply to all types of meter deployments.

Under the current regulatory arrangements, there are no clearly defined processes to be followed, and there is a limited amount of information recorded and shared regarding site defects. Better-defined arrangements are needed, especially for accelerated deployments. The Commission expects that the proposed arrangements will:

- encourage more customers (who have the financial means) to remediate as they would be promptly reminded by their retailer and given sufficient opportunity to remediate to enable the installation of a smart meter[76]
- support greater transparency of site defects and improved deployment efficiencies through a reduction in wasted site visits.

Figure B.1 below outlines the proposed entire end-to-end process to be followed for sites with defects. The process outlines arrangements for notifications and exemptions where site defects are encountered and requirements for record-keeping.

Figure B.1: End-to-end process for managing site remediation



Source: AEMC

Notifying customers of the need to remediate

76 applying to customers who are willing and able to remediate their site defect.

It is proposed that if a meter upgrade cannot be conducted due to material defects at a customer's site, then the customer should be provided with further information regarding the defects. As shown in Figure B.1, it is proposed that:

1. **If the MC discovers a defect with a site**:
   - The MC leaves a defect notice with a customer outlining the defects in the customer's site due to which a metering upgrade could not occur.
   - The retailer sends a notice to the customer of the need for remediation as soon as practicable
2. **If the customer has not remediated the site after two months and informs the retailer**:
   - The retailer is required to send a second notice to the customer within three months of issuing the first notice to the customer.
   - The notices would outline any schemes or funding arrangements available to the customer for undertaking remediation work.
3. **If the customer has not remediated within two months of when the retailer issued the second notice**:
   - The retailer is required to record the status of site remediation (successful or unsuccessful) in the retailer's next AER quarterly performance report.
   - The retailer is then exempted from following the installation timeline requirements for the site.
4. **If a customer does undertake remediation and notifies the retailer of remediation undertaken**:
   - The retailer would be required to progress the upgrade under the original timeline requirements corresponding to the type of meter deployment.

Keep track of sites needing remediation

In addition, it is proposed that the information regarding a site's defects status is gathered and shared with the key stakeholders. It is proposed that retailers record information on:

- whether an NMI has site defects preventing meter replacement (i.e., a defect flag)
- reasons for the defect
- the number of defect notices that has been issued to the customer
- the date of issue of the defect notice(s)
- the addresses of the site(s) that require remediation.

Retailers would record the above information in a database shared across retailers such as market settlement and transfer solutions (MSATS).

> **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?

B.4.4 Customers should retain responsibility for remediating sites

The Commission considers that customers should retain the responsibility for undertaking site remediation. The Commission notes suggestions from some stakeholders for transferring the responsibility for remediation to the DNSPs. However, such arrangements will likely require significant changes to contestability frameworks to enable DNSPs to undertake remediation work and arrangements for large-scale socialisation of remediation costs. Reforms to jurisdictional arrangements would be needed to allow these changes.

The Commission does not consider it appropriate to introduce stringent requirements for customers to remediate site defects as it could undermine the smart meter deployment's social licence and lead to poor customer outcomes.

B.4.5 Government assistance for customers could support a more equitable deployment

The Commission considers that additional measures, including financial support for customers to undertake remediation of site defects, would enable a more equitable and uniform deployment of smart meters and enable more significant levels of uptake to be achieved.

Financial barriers associated with remediation costs are a key underlying reason for customers' lack of timely site remediation. Without additional measures, including financial support, some customers will likely be left out of the smart meter deployment. Customers in vulnerable circumstances, such as low-income families, would face more significant risks of missing out on upgrades due to site defect issues.

Governments are likely to be better placed than the national Rules framework to help level the playing field for customers by implementing arrangements to help support customers in remediation.

Some customers could be left behind in the deployment

Under the existing arrangements, customers would continue facing financial barriers in undertaking the necessary remediation work to enable metering upgrades. The proposed notification and record-keeping arrangements will not lower financial barriers to undertaking remediation on their own. It will mean some customers may not be in a position to undertake remediation and will miss out on a smart meter upgrade.

This would lead to an inequitable and non-uniform deployment of smart meters. Some customers will receive access to smart meters and their associated benefits, while others will not, depending on the state of their electrical installation and the ability to afford site remediation.

Vulnerable customers face greater risks of missing out

Vulnerable customers would face higher risks of being excluded from the smart meter deployment due to remediation issues. This is because they are more likely to be in positions where decisions making regarding remediation is out of their control and face higher financial hurdles for undertaking remediation.

Vulnerable energy customers can overlap with the more socio-economically disadvantaged parts of the community. Customers who don't own their own homes or live in social or public housing are more likely to fall into the vulnerable energy customers category. In many cases, such customers may not have the required authority to make decisions regarding undertaking remediation. Electrical installations generally form part of the infrastructure that the building owner or operator is required to provide and maintain.

The financial barriers to remediation will likely be more pronounced for vulnerable customers. For any amount of expenditure required for remediation, vulnerable customers, especially those with low income, will be less likely to be able to afford it. This will mean more vulnerable customers, even those who own their own homes and have a decision right in undertaking remediation, may not receive a smart meter due to their inability to afford the up-front costs of undertaking remediation.

An inequitable deployment would leave vulnerable customers less able to benefit from the smart metering upgrades. It will impact their ability to receive benefits such as access to a wider range of energy retail offers, different billing cycles, quicker connections and reconnections and improved access to their usage data enabling them to budget their energy expenditure better. As found by Newgate Research, vulnerable customers, in particular, highly value the ability to improve their planning and budgeting of their electricity bills via access to more frequent bills enabled by smart meters.[77]

The National framework has limited ability to address these challenges

Beyond measures for better capturing and sharing of site defect information, such as those outlined above, the Commission has not identified other clear paths to address these issues through the NER or NERR. Enabling funding arrangements for customers, vulnerable or otherwise, or solutions to address the lack of customer agency to undertake remediation is not likely to be feasible through a national Rules obligation alone.

Funding remediation for customers, such as through DNSP sinking fund arrangements, would be challenging to deliver through the NER or NERR. As customers remain responsible for undertaking remediation, they will need to engage electrical contractors to undertake the remedial works, which jurisdictional regulations govern. As most electrical contractors would not be registered participants under the NER, the Commission would not be able to make Rules that provide electrical contractors with a right to pass through costs to DNSPs. Furthermore, enabling DNSPs to recover these costs from customers is also expected to be challenging because DNSPs would not be providing any services to the customers. As such, the current cost recovery mechanisms in the NER would likely be unsuitable.

77 Newgate Research Final Report, p. 43.

The Commission would not be able to address situations where customers cannot authorise remedial works for their premises, particularly if a customer is renting or is an owner-occupier within a strata scheme. These matters relate to issues beyond those covered under the NER and NERR. To achieve NEM-wide implementation success, the Commission considers it relevant to coordinate with the specific jurisdictional conditions and delivery chains for strata schemes to minimise potential failure points of its recommendations.

Governments could consider levelling the playing field for customers

Governments and jurisdictional frameworks are better placed to consider the broader equity and social considerations of the deployment of smart meters and implement arrangements to help support customers in remediation.

If a more uniform and equitable deployment of smart meters is required to achieve the desired social policy objectives, then Governments would be well placed to consider the desired level of cost socialisation to achieve their respective social and equity objectives and put in place arrangements that help customers remediate site defects.

Governments currently play an important and active role in levelling the playing field for customers and have arrangements that aim to deliver broader policy objectives, including promoting equity among energy consumers and providing energy affordability and emissions reduction.

A range of concessions and rebates are made available to customers by Governments. The various schemes provide different levels of payments and apply to different energy customer subsets depending on their eligibility. For example, concessions and rebates are provided to:

- customers holding eligible concessions cards such as pensioner or health care cards
- customers on life support
- customers with medical conditions
- customers to incentivise the installation of energy efficient equipment and appliances

Jurisdictions could develop similar schemes to support more customers undertaking site remediation to enable more widespread and equitable deployment of smart meters in the respective jurisdictions.

The Commission can support the development of targeted schemes by governments seeking to progress measures to enable a deployment of smart meters that better aligns with their broader policy objectives.

B.5 Improving industry coordination and minimising negative customer impacts in shared fusing scenarios

The Commission recommends further developing and using a ‘one-in-all-in’ approach to meter replacements to support improved industry coordination to deliver enhanced meter replacement efficiency and the customer experience in scenarios where meters for customers on a shared fuse need to be replaced. The approach has been developed through close stakeholder collaboration, and it can help deliver significant improvements to meter replacements in shared fusing scenarios.

The Commission seeks stakeholders' feedback on this approach — particularly concerning aspects of the process that need further development.

B.5.1 Meter replacements for customers with shared fusing pose challenges

Customer sites with shared fusing, typically found in multi-occupancy dwellings, pose a barrier to rolling out smart meters in certain areas and usually result in a negative customer experience. Shared fusing tends to be more prevalent in older electrical installations. Jurisdictional regulations now require individual isolation of meters in new electrical installations. Vector indicates that isolation issues, including shared fusing, accounted for 7.6 per cent, 2.6 per cent, and 9.2 per cent of unsuccessful meter installations in New South Wales, Queensland, and South Australia, respectively, in 2020.[78] Gathered from submissions to the Consultation Paper and Directions Paper, the three main issues are:

- interrupting supply to replace one meter will interrupt the supply to multiple customers on the same fuse
- multiple parties are required to coordinate to ensure they are on the site at the same time for meter replacement
- replacing meters on a piecemeal approach leads to customers facing multiple supply interruptions, installation delays and costly replacements due to multiple site visits.

The *MC Planned Interruption* rule change[79] made in 2019 partly resolved the issue, but a new process is required in an accelerated deployment.

B.5.2 Stakeholders supported developing options to support better coordination

In the Directions Paper, the Commission sought stakeholder suggestions and feedback on approaches that could improve the efficiency of installing meters in multi-occupancy situations.

Many stakeholder submissions support further developing a 'one-in-all-in' approach to provide an efficient and cost-effective installation process. The general feedback was that it would improve the efficiency of meter deployment, reduce costs (e.g., reduced number of site visits), and improve coordination between market participants in the installation process for multi-occupancy sites.[80] Under this approach, replacing one meter on a shared fuse triggers all other legacy meters on the shared fuse to be replaced simultaneously. Customers on the same shared fuse would not be able to opt-out of meter exchange. Itron views that the approach could simplify the installation process and minimise supply disruption and disconnection.[81]

78 Vector submission to Directions Paper, p. 17.

79 AEMC, *Introduction of metering coordinator planned interruptions*, May 2020, https://www.aemc.gov.au/rule-changes/introduction-metering-coordinator-planned-interruptions.

80 Feedback in the Installations Working Group, Reference Group, and submissions to Directions Paper: Origin, p. 2; Bright Spark Power, p. 11; EnergyAustralia, pp. 11-12; Essential Energy, pp. 8-9; Solar Analytics, p. 8.

81 Itron submission to Directions Paper, p. 19.

In submissions to the Directions paper, stakeholder suggestions for how the 'one-in-all-in' approach could work include:[82]

- using a collaborative industry approach, leveraging resources and capabilities of market participants for operational efficiencies
- appointment of a single MC and/or appointing the DNSP as the MC for multi-occupancy sites
- use a 'standard' contract between all retailers and MCs
- sharing of costs among market participants.

Considerations raised by stakeholders in submissions to the Directions Paper and the Reference Group include:[83]

- direct impact on customers, including upfront costs
- payment/cost recovery associated with site remediation
- consumer protections, such as allowing the option to switch off communications
- changes to a retailer's obligation when its customer switches to another retailer.

Some retailers suggested a different approach to addressing multi-occupancy issues by requiring DNSPs to install isolation devices. This approach was discounted during the *MC Planned Interruption* final rule. At the time, the Commission said that the proposed alternative solution was not adopted in the final rule because the responsibilities and accountabilities for meter panels, isolation devices and similar assets should be considered under a holistic process to determine the most appropriate safe and efficient management of issues associated with the devices. The Commission is still of the view that this approach would pose significant legislative and implementation challenges that would not assist in accelerating smart meter deployment.

B.5.3 A one-in-all-in approach could better support meter replacements in shared fusing scenarios

The 'one-in-all-in' approach seeks to improve coordination, provide guidance and strengthen the roles of market participants for an efficient installation process in multi-occupant sites. Under this approach, a metering upgrade for one more of the customers on the shared fuse will trigger the upgrade for all customers and require the meters for all customers on the shared fuse to be upgraded concurrently. The proposed approach seeks to encourage better coordination amongst the parties in facilitating and undertaking the metering replacements. The Commission considers that the one-in-all-in mechanism significantly improves the process for upgrading metering installation in multi-occupancy scenarios because it can:

- help support the acceleration of smart meter deployment by supporting multiple meter replacements at once
- reduce the number of interruptions of supply to customers by encouraging replacements to happen using one or fewer supply interruptions compared to the current scenario

82 Submission to Directions Paper: Bright Spark Power, p. 11; South Australia, pp. 6, 14, 15; ENA, pp. 16-17.

83 Submissions to Directions Paper: PIAC, p. 18; Essential Energy, p. 9.

- reduce delays in meter replacement and the number of site visits required by metering providers (MPs) and DNSPs
- minimise the costs of meter replacement by reducing the need for multiple MP and DNSP visits, serial outages of supply to the customers and enabling better scale efficiencies.

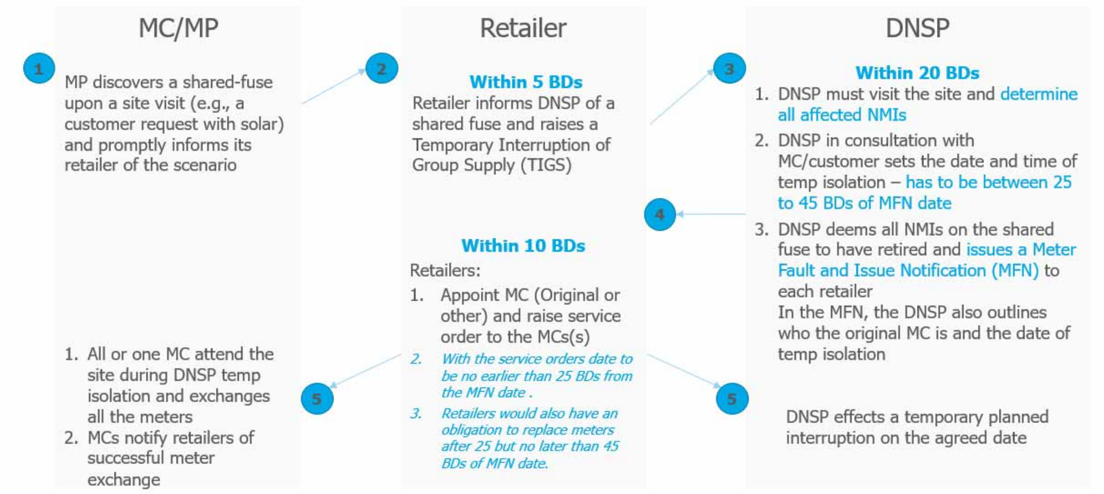
The Commission has also examined other potential options to improve meter replacements in shared fusing scenarios and considers the one-one-all-in approach to be preferable. The following section outlines the details of the proposed approach.

The multi-occupation scenario — How one-in-all-in works

The one-in-all-in approach under the Multi-occupation scenario will be applicable to sites where metering replacements aren't prevented from going ahead due to site defects (e.g., asbestos, meter board upgrades required and wiring issues). Where such issues are found, the usual arrangements for remediating sites will be applicable, whereby the customer will need to remediate the defects before the upgrade can progress. The Commission also notes that site defects are common multi-occupancy scenarios, and remediation resolves the shared fusing issues.

Figure B.2 below shows a step-by-step process of the proposed *Multi-occupation scenario*, while Figure B.3 outlines the timeframes.

Figure B.2: Step-by-step process of the proposed multi-occupation scenario



Source: AEMC

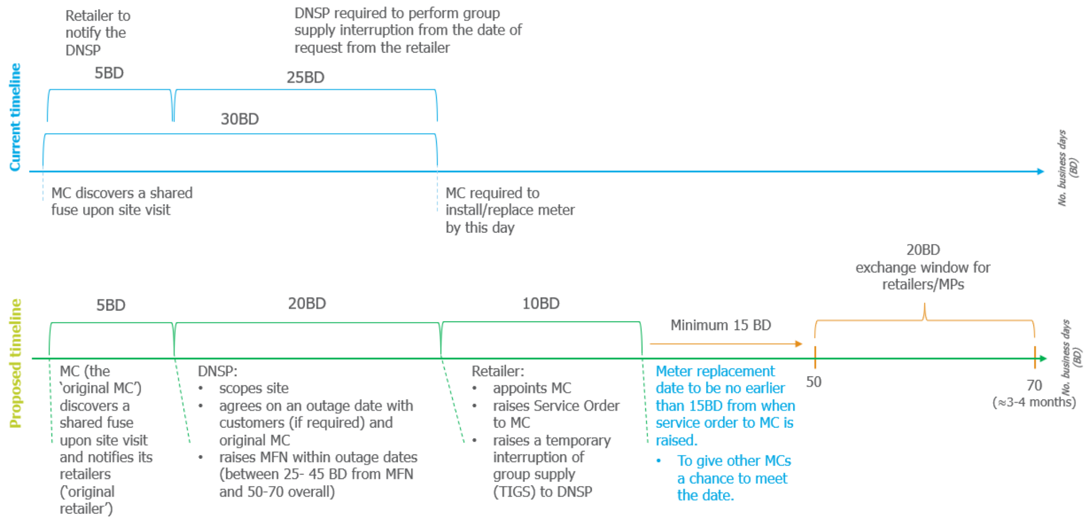
Where applicable, the one-in-all-in process under the multi-occupation scenario will involve the following steps.

- **Step 1 — Discovery of shared fusing:** An MP may discover a shared fusing situation when visiting a site to undertake a meter upgrade for any type of deployment or through other means. The MC must promptly inform the retailer, who originally authorised the MP's visit to the site, regarding shared fusing and trigger the one-in-all-in mechanism if it considers the meters for all customers on the metering board can be upgraded without needing significant remedial works to be undertaken by the customer. These metering parties are referred to as the 'primary MP' or 'primary MC' for the one-in-all-in mechanism.

- **Step 2 — Raising of temporary isolation request:** The retailer associated with the discovery of the shared fuse is then required to inform the DNSP of the shared fuse and raise a request for a Temporary Interruption of Group Supply (TIGS), as per current arrangements and practice. A retailer has a time frame of five business days to request temporary isolation.
- **Step 3 — DNSP visit and notification to retailers:** Within 20 business days of receiving the request, the DNSP must:
  - determine all affected NMIs on the shared fuse
  - set a date and time for temporary interruption of group supply. In setting the duration of the outage, the DNSP should consider the length of time reasonably required to undertake the required upgrades. The date of the temporary interruption set by the DNSP will need to be between 25 and 45 business days from when the retailers are notified in the step below. This provides at least 20 business days for the primary MC or MCs[84] to plan and schedule meter replacement(s).
  - deem all the legacy meter (NMIs) on the shared fuse to be no longer fit for purpose and issue a notification to the retailers of the respective NMIs. This could make use of the existing Meter Fault and Issue Notification (MFIN) processes. The notification should also outline details of the primary MC and the date and time of the scheduled temporary isolation. This information should enable retailers to appoint the primary MC as their MC for the site and inform them to raise a service request to conduct the replacement at the same date and time as the temporary isolation.
- **Step 4 — Appointment of MCs**: Within 10 business days of receiving a notification from the DNSP, the retailers will be required to appoint an MC (the primary MC or one of their choosing) and raise a Service Order (SO) for meter replacement(s). The Commission considers that providing at least 15 business days would allow metering parties to align the received SO to the TIGS in an efficient and cost-effective manner. Therefore, the Commission proposes to require the service order request date to be at least 25 days from the date the notification was received. There would also be a requirement for the retailers to replace meters within 25 and 45 business days of the replacement notice date to ensure meter replacement takes place.
- **Step 5 — Meter replacement:**Under this step, the DNSP causes the temporary isolation at the set date and time, and the metering party or parties visit the site during the temporary isolation period to undertake the meter replacements.

84 Retailers can choose to appoint a single MC (e.g., the Primary MC) or appoint their own.

Figure B.3: Timeline for a 'one-in-all-in' approach



Source: AEMC

Under the proposed 'one-in-all-in' approach, retailers can either appoint the Primary MC or an MC of their choice. If all or most retailers in the multi-occupancy site appoint a single MC (i.e., the Primary MC), the Commission considers that efficiencies could be maximised — communication, coordination, and the installation process would be more streamlined and cost-effective.

The retailers would still face an incentive to undertake the replacement during the temporary isolation window outlined in the DNSP's notification because the retailers would face additional costs if they were to seek another isolation from the DNSP to conduct their meter replacement at a different time. This should meter replacements to the conducted using few planned network outages.

The Commission believes that assigning roles, responsibilities and clear timelines for each market participant within the process is required to facilitate effective coordination among multiple parties and improve the efficiency of smart meter deployment. It is considered to provide foresight, guidance and flexibility in scheduling meter installation in complex scenarios that involve a shared fuse. As a result, it should lead to reduced administrative burden and costs and minimise negative customer impacts such as the number of supply interruptions.

In developing the 'one-in-all-in' approach, with stakeholders, the Working Groups generally viewed the approach as a practical improvement to the installation process of multi-occupancy sites.

Participants noted that retailers may not have a solid incentive to appoint a single MC and that the proposed process may not be suitable for one party to play the planning and coordinating role. In addition, stakeholders suggested that MSATS may require changes to, e.g., malfunction notice fields.

Notifications to other parties and customers

Some stakeholders have sought further clarification regarding the party responsible for notifying customers regarding the planned interruption to their supply for the meter replacement under the proposed process. The Commission provided preliminary comments on which party is responsible for issuing a planned interruption notice (PIN) in certain circumstances.[85] In response, PLUS ES suggested that the market participant scheduling the date of a planned interruption should be accountable for giving the affected customer the PIN under the Rules. PLUS ES also indicate that irrespective of a retailer or distributor's planned interruption, DNSPs should be required to inform relevant parties, including metering parties, of their scheduled interruption date within a practical time frame that would enable MCs to meet their replacement time frame obligations.[86]

The Commission considers that the proposed 'one-in-all-in' approach would address the above-mentioned issues raised by PLUS ES. The process outlines the responsibilities of each market participant and the time frames to which obligations are to be met. The intent is to allow for effective communication and coordination within a planned interruption, including distributing PINs involving multiple parties. The 'one-in-all-in' approach should also practically allow each market participant to meet their respective obligations. If a customer has engaged a non-market participant, it is outside the Commission's remit to clarify notification requirements as jurisdictional arrangements govern it.

Issues for further consideration

The one-in-all-in proposal outlined above provides a process flow for replacing meters in shared fusing scenarios. There are some consequential considerations arising from the process that needs further exploration. These include the allocation of temporary isolation costs between retailers, the suitability of the current temporary isolation services and the need to clarify the party responsible for notifying customers of the planned interruption.

- **Payment of TIGS**: The original retailer raising the TIGS request would face the costs of raising the request even though other retailers would also be using the temporary outage for meter replacement purposes. An approach to allocating costs could include DNSPs recovering costs from the relevant retailers (all on the shared fuse with a legacy meter) on a pro-rata basis.
- **Amendments to temporary isolation service**: distributor-planned network interruptions for meter replacements are an ancillary network service with a regulated price. There may be a need to consider further if the existing temporary isolation or ancillary network services could accommodate step 2 of the one-in-all-in process.

85 See page the Directions Paper https://www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf#page=109 .

86 PLUS ES submission to Directions Paper, pp. 33-34.

- **Party responsible for sending the PIN**: Stakeholder feedback has highlighted the need to clarify who should notify customers of planned interruptions while replacing meters in shared fusing scenarios. This will need to be further considered in the context of the one-in-all-in approach.

Request for stakeholder feedback

The Commission invites feedback from the stakeholders regarding the appropriateness of the approach, including the proposed timelines, roles and responsibilities, steps involved, and issues for further consideration.

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 time frames 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 time frames?
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?

B.5.4 Other approaches are less preferable

In developing its recommendations to address shared fusing issues, the Commission considered other options raised by stakeholders, including the possibility of requiring the DNSPs to install isolation devices on all sites with shared fusing. The Commission finds that this approach is less preferable in allowing efficient deployment of smart meters in multi-occupancy sites as it is not well suited to supporting an accelerated deployment of smart meters, and there are regulatory barriers to its implementation in the national and jurisdictional frameworks.

Requiring DNSPs to install isolation devices at sites with shared fusing would require additional steps to be undertaken before metering installation. If an approach is adopted whereby shared-fusing sites are identified using surveys before the installation of isolation devices by DNSP, it would mean that the isolation will need to be resolved before metering installations under an accelerated deployment. Alternatively, if isolation issues are resolved by DNSP's installing isolation devices where shared fusing is found, it would lead to several additional steps needing to be taken by DNSPs. For example, inspecting a site, scheduling a planned interruption and installing isolation devices before the retailers and MCs could schedule and undertake replacements. Under both approaches, the additional steps would slow smart meter deployment.

Isolation devices will need to be installed next to and upstream of the customer's metering installation. The DNSPs could face barriers in installing, owning and operating such assets. Under the regulatory framework, the boundary between a customer and DNSP's responsibility for supply is set at the connection point. The DNSPs face restrictions in owning and operating assets beyond the connection point.[87] Restricted assets for DNSPs are defined as:

An item of equipment that is electrically connected to a retail customer's connection point at a location that is on the same side of that connection point as the metering point, but excludes:

- such an item of equipment where that retail customer is a DNSP for that connection point; or
- a network device.

The Commission has also considered if isolation devices could be considered network devices, which are defined as apparatus or equipment that:

- enables a DNSP to monitor, operate or control the network for the purposes of providing network services, which may include switching devices, measurement equipment and control equipment;
- is located at or adjacent to a metering installation at the connection point of a retail customer
- does not have the capability to generate electricity.

Based on this definition and the obligations on DNSPs for network devices, it is unclear if the DNSPs could install isolation devices as network devices. DNSPs may also have different interpretations of these arrangements. Given the ambiguity in the DNSPs' ability to install isolation devices under the network devices provisions, the Commission considers that it would not be prudent to oblige DNSPs. Amendments to the definition of network devices could have flow-on impacts on the contestability framework.

The installation of isolation devices by DNSPs would also face barriers under jurisdictional regulatory arrangements. For example, under the New South Wales Service and Installation Rules, the customers must arrange and install a meter protection device at their cost.[88] Installation of isolation devices by DNSPs may breach these requirements.

87 AEMC, Final determination, contestability of energy services, p. 54.

88 New South Wales Department of Planning, Industry and Environment, Service and Installation Rules – Annexure Metering requirements, clause 2.1.

C IMPROVING THE CUSTOMER EXPERIENCE IN METERING UPGRADES

Stakeholder feedback and the Commission's Directions Paper identified several issues faced under the current metering and tariff arrangements that impact customers' experience in the smart meter deployment. The key issues identified included a lack of upfront information available to customers, delays in replacing malfunctioning meters, inability to request an upgrade for any reason and changes in customer tariffs triggered by metering upgrades.

This appendix outlines the Commission's draft recommendations to improve customer experience by supporting improved customer awareness, timeliness of installations, and more explicit rights for customers while supporting a smoother transition to smart metering and cost-reflective pricing.

BOX 6: RECOMMENDATIONS TO IMPROVE CUSTOMER EXPERIENCE

1. Enhancing the provision of information to customers and clarifying customer's rights:
   a. requiring retailers to provide important information to small customers regarding smart meters prior to any upgrades in a clear, streamlined and consistent way
   b. requiring the development of a smart meter information website to enable consistent and customer-friendly information to be delivered to customers
   c. enabling customers to request a smart meter from the retailer for any reason and requiring retailers to install a smart meter on receipt of such a request.
2. Reducing delays in the installation of smart meters by:
   a. implementing a practicable replacement time frame for malfunctioning meters by setting different timelines of 15 business days for individual meters malfunctions and 70 business days for family failure malfunctions identified through sample testing
   b. removing the malfunctions exemptions process currently administered by AEMO, applicable to meters of small customers.
3. Safeguarding customers from tariff changes associated with metering upgrades by:
   a. enabling measures to facilitate a smoother transition to cost-reflective pricing under an accelerated smart meter deployment.

The Commission has identified regulatory changes required for recommendations 1, 3, 4, and 5 (see Table C.2). Feedback is sought from stakeholders on the Commission's proposed approach to address the identified issues as well as the proposed changes to the NER and NERR to give effect to the draft recommendations in chapter 3.

C.1 Enhancing information provision and clarifying customer rights

C.1.1 Enhanced information provision to customers

The Commission recommends enhancing up-front and customer-friendly information to customers to support the deployment of smart meters and empower them to make the best of their metering upgrades under all meter deployments. The two proposed measures are:

1. the expansion of information required to be provided to customers from their retailer before the meter upgrade takes place, and
2. the development of a smart energy website to provide a single location that contains customer-friendly information regarding smart meters and accelerated deployment.

Table C.1: **Proposed line items for the two proposed measures**

INFORMATION RECOMMENDED FOR NOTICES	INFORMATION RECOMMENDED FOR THE SMART ENERGY WEBSITE

• The reasons for the proposed new meter deployment (planned, failure, retailer-led or new connection)
• An indicative timeline for when the customer would receive the smart meter (this can be a date range)
• How the customer can access their smart meter data
• The customer's rights and responsibilities regarding the meter installation (including remediation work)
• Any upfront charges the customer will incur under their retail contract as a result of the new meter deployment
• Any changes to the consumer's retail contract resulting from the meter installation, including tariff changes (if applicable)
• A summary of the services available to the small customer as a result of obtaining a smart meter (including how small customers can benefit from smart meters)
• The party the customer should contact to resolve issues, as well as dispute resolution options
• The retailer's contact details
	• The benefits of smart meters to customers.
	• The benefits of smart meters to the electricity system.
	• The role of a smart meter in the energy transition.
	• How customers can make the best use of smart meters.
	• How customers can access their energy usage data.
	• Potential changes to a customer's retail bill due to a change in meter.
	• Description of the different types of cost-reflective tariffs and how customers could make the best use of each
	• Roles and responsibilities of customers and industry participants:
	  • For remediation.
	  • Regarding notices.
	• Any other relevant information, e.g., data privacy.

INFORMATION RECOMMENDED FOR NOTICES	INFORMATION RECOMMENDED FOR THE SMART ENERGY WEBSITE
• Contact details of interpreter services in community languages	

C.1.2 Current arrangements offer minimal information to customers before an installation

The current framework does not enable consistent information provided to customers during meter upgrades. Customers only receive information about metering before retailer-led deployments, and the notice is not required to include information to enable customers to benefit from the smart metering installation.[89]

Retailers must currently provide two such notices to customers prior to the meter exchange. The notices are required to outline the customers' ability to opt-out, the expected date and time of the replacement, any up-front charges with installation, retailer's contact details and contact for interpreter services. The Commission is making recommendations to remove one of these notices and the customer's ability to opt-out. This necessitates changing the current information arrangements.

The Commission understands that customers generally are not provided with the reason for a meter exchange, the potential flow-on impacts, or how they could benefit from their new meter. Other meter exchange types, including those conducted with a retailed planned interruption, can only be performed by issuing customers a PIN. The PIN is only required to outline the expected date, time of the outage, and whether the interruption is related to a meter exchange.

C.1.3 Customers lack the required information for a positive experience with smart meters

The current arrangements create an information problem. Newgate's research indicates that:

- Customers currently may not receive adequate information on the process of obtaining a meter, responsibilities and accountabilities under the installation process, the benefits that smart meters can provide and any changes resulting from the installation of the smart meter, such as tariff changes.
- Many customers had not been provided with information on how to make the most of their smart meter when it was installed. Some were unaware they could access an app or portal to gain greater insight into their electricity usage.
- Many customers without smart meters were unsure about whether they would request to have a smart meter installed, even after finding out more information about the benefits and features.
- Customers were unsure if a smart meter was worth the effort, especially without clarity around any additional costs involved in installing one and the implications of being forced onto a time-of-use tariff.

89 NERR Rule 59A.

This information problem leads to insufficient incentives, guidance, and obligations to provide up-front and customer-friendly information. As a result, customer experiences with smart meters can be poor and impede intended installation requests.

The Directions Paper proposed increasing information available to customers based on findings from the Newgate research that showed significant increases in consumer awareness and acceptance, which the Commission considered would improve the customer experience:[90]

- Only 53 percent of residential customers recalled receiving any information when their smart meter was installed, and only 36 percent were told how to access an app or portal to track energy usage.
- Those who recalled receiving information with their smart meter are more likely to feel optimistic about having a smart meter installed at their property.
- Following exposure to the features of smart meters, sentiment among residential customers shifted to be significantly more positive. Businesses also became more positive, although this change isn't statistically significant.

C.1.4 Stakeholders reaffirmed the need to provide better information to customers

The preliminary recommendation in the Commission's Directions Paper suggested what information could be included in the notice and sought feedback from stakeholders. Most stakeholder submissions support further information being provided to customers before a meter installation.[91] Some retailers and metering parties see value in streamlining and removing duplication with a current obligation on retailers under clause 59A of the NERR.[92] Some stakeholders support the retailer being the party to provide the information notice.[93] Some stakeholders provide suggestions for what information should be included in an information notice, such as:[94]

- customer's entitlements and rights, including data access
- customer's roles and responsibilities
- the role of smart meters in the energy transition
- cost arrangements, including remediation if required
- services that smart meters can provide (e.g., timely usage information)
- implications of tariff reassignment, if any
- dispute resolution process.

90 Newgate Research Final Report, pp. 32-33.

91 Submissions to the Directions Paper: ACOSS, pp. 9-10; PIAC, p. 14; ECA, p. 5; AEC, p. 7; Alinta, p. 8; Bright Spark Power, p. 8; EnergyAustralia, p. 10; ReAmped, p. 2; Essential Energy, p. 1; Ausgrid, p. 3; CEC, p. 9; Green Metering, p. 10; EDMI, p. 6; Wattwatchers, p. 16; Solar Analytics, p. 7; PLUS ES, p. 22; Vector, p. 13; NECA, p. 6, 8; Endeavour Energy, p. 16; EWON, p. 5.; Secure Meters, p. 8.

92 Submissions to Directions Paper: Alinta Energy, p. 8; Green Metering, p. 10; Red Energy and Lumo Energy, p. 4; Simply Energy, pp. 3-4; Tango Energy, p. 2; Vector, pp. 13.-14.

93 Submissions to Directions Paper: Green Metering, p. 10; ACOSS et al., pp. 9-10; Ausgrid, p. 6; AEC, p. 5,7; Endeavour Energy, p. 16; Essential Energy, p. 8; PLUS ES, p. 22; Solar Analytics, p. 7; Energy Queensland, p. 21.

94 Submissions to Directions Paper: ACOSS et al., pp. 9-10; PIAC, p. 14; Essential Energy p. 1.

Stakeholder opposition to specific information notices includes concerns for:[95]

- a lack of flexibility and duplication of information
- likelihood to promote smart meter uptake
- additional back-office costs
- whether an independent party should provide the information notice:[96]
    - whether it should be provided by the federal government, jurisdictional governments, an ombudsman, or a market body.
    - the Commission also recognises that some retailers opposed involving an independent party because it is unnecessary – there is currently existing information.[97]

C.1.5 Extending information provision requirements to all types of meter deployments for improved customer outcomes

The Commission's draft position is that information provided to customers regarding metering upgrades must be strengthened for all meter deployment types. Customers receiving up-front information in a customer-friendly manner regarding the smart meter deployment will enable them to make informed decisions, improve social licence and encourage a smoother deployment.

The Commission considers that extending information provided to customers could improve customer outcomes by equipping them with the right knowledge to make informed choices. Under this proposal, small customers receiving a smart meter upgrade would be provided with a smart meter information notice by their retailer outlining essential information regarding the upgrade prior to the deployment.[98] The retailer would be required to send a smart meter information notice to the customer before installation for all types of meter deployment, including retailer-led deployment, malfunctions, programmed deployment under acceleration and new connections.

The Commission considers retailer are best positioned to provide the information as they have a direct relationship with the customer in meeting their electricity needs and preferences. The Commission proposes the following information to be included in the information notice as a minimum:

- the reasons for the proposed new meter deployment (planned, failure, retailer-led or new connection)
- an estimated timeline for when the customer would receive the smart meter (this can be a date range)
- how the customer can access their smart meter data
- the customer's rights and responsibilities regarding the meter installation (including about remediation work)

95 Submission to Directions Paper: EnergyAustralia, p. 10; Red Energy and Lumo Energy, pp. 4-5; MEA Group, p. 3; AGL, pp. 13-14; Simply Energy, pp. 3-4.

96 Submissions to Directions Paper: PIAC, p. 14; Wattwatchers, p. 16; PLUS ES, p. 22; MEA Group, pp. 3-4.

97 Submissions to Directions Paper: EnergyAustralia, p. 2; Green Metering, p. 10.

98 This provision would only apply to customers with a legacy meter receiving an upgrade.

- any upfront charges the customer will incur under its retail contract because of the new meter deployment
- any changes to the consumer's retail contract resulting from the meter installation, including tariff changes (if applicable)
- a summary of the services available to the small customer as a result of obtaining a smart meter
- the party the customer should contact to resolve issues, as well as dispute resolution options
- the retailer's contact details
- contact details of interpreter services in community languages.

The Commission considers that this information will help the customers better understand what the metering installation means for them, their rights and responsibilities, the opportunities and options unlocked and the importance of metering upgrades. It should also empower them to realise better benefits from their metering upgrade.

This requirement would also protect customers from potential costs associated with the metering exchange. Customers will be informed up-front if the retailer chooses to charge the customer any up-front metering costs. Customers would have the opportunity to consider paying up-front costs with their retailer or switching to another retailer that does not charge up-front fees.

Implementation considerations for the new retailer information notice

It is recommended that the information notice can be delivered by the retailer to the customers in a flexible manner. Under the proposed arrangements, the notification must be provided to the customer no earlier than 60 business days but at least ten business days before the proposed replacement date. This should enable customers to receive the information promptly. It should also provide sufficient flexibility for the retailer and metering parties to schedule and efficiently undertake the meter deployment. The information notice could be sent with the Planned Interruption Notice under rule 59C of the NERR.

The information included in the notice is also required to be consistent with the information provided on the 'Smart Meter Information' website outlined below, where applicable. This should enable retailers to leverage or point to the information available on the website rather than develop their own content. This should help with consistent customer messaging and minimise the regulatory burden on retailers.

In developing the information to be included, the Commission has considered feedback including some concerns regarding specific information requirements proposed in the Directions Paper. Under the proposed information notice, retailers would not be required to include customer-specific or bespoke information. Most of the information should be applicable to the broad customer base of the retailer.

Details on the proposed changes to the NERR and retailer obligations to enable the smart meter information notice requirements are provided in Table C.2 (see amendments 3 and 5).

C.1.6 Developing a smart metering information website

The Commission proposes the development of a smart metering information website containing key information for customers and industry for the transition to smart metering. It will enable customers to access the relevant information from an independent and trusted source in a transparent and customer-friendly manner.

This initiative will help deliver a better outcome for customers by supporting the following:

- the provision of easily accessible and digestible information to customers enabling them to make informed choices
- efficient and consistent information provided to customers by retailer
- greater clarity and agreement in the sector regarding issues such as the roles and responsibilities of the parties involved in metering
- better dispute resolution and customer experience.

Doing so will also deliver a better social licence for the transition to smart metering.

It is envisaged that the website would include information that could assist the transition to smart metering and enable customers to make the best use of smart meters, including:

- the benefits of smart meters to customers
- the benefits of smart meters to the electricity system
- the important role of smart metering in the energy transition
- how customers can make the best use of smart meters
- how customer access their energy usage data
- roles and responsibilities of customers and industry participants
  - For remediation
  - Regarding notices
- any other relevant information.

Implementation of the smart energy website

To support the smart meter deployment, the smart energy website would need to be developed as soon as possible, or at least before the acceleration begins (i.e., before 2025). The Commission considers that the website must be in place promptly to better serve its function as a source of truth for customers and industry and to provide retailers enough time to input the information into their notices.

A key consideration for developing and maintaining the primary source website is who should be responsible. The Commission considers this vital to the website's success because it would affect the information's reliability and the perception of smart meters by customers and the industry. To serve as an effective source of truth, it would need to be developed by an independent party (or parties) with a level of authority in the sector.

> **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?
> 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?

C.2 Allowing customers to receive a smart meter from a retailer for any reason

The Commission recommends clarifying in the NERR that retailers would be required to install a smart meter upon customer request. This recommendation has remained unchanged since the Directions Paper.

C.2.1 Concerns regarding some retailers refusing customers' requests to install smart meters

The current framework does not specify that a retailer must install a smart meter at a premise upon a customer's request, for any reason or under all circumstances. For situations where the customer's request does not include a connection upgrade or a rooftop solar system installation, the Rules do not provide explicit direction on whether retailers are obliged to install a smart meter.

The Commission has received informal correspondence from customers who have been declined a smart meter or were charged an up-front fee for displacing the legacy meter. The Commission understands that retailer's reasons for refusing or charging the customer are based on having no technical reason to replace an existing meter – the metering installation has not failed, is still functioning, and is compliant with the NER.

Smart meters can benefit consumers, the market, and the whole electricity system. The deployment of smart meters by retailers can help realise these benefits more quickly and possibly at a lower cost than what could be expected if consumers had to actively opt-in. This allows the retailer to deploy meters to their customers where they see a business case. If there is no business case, the site can retain its existing working metering installation. This may not consider the service benefits the consumer demands and should not go unmet.

C.2.2 Stakeholders agree that customers should be able to request a smart meter for any reason

In submissions to the Directions Paper, most stakeholders support customers being able to request a smart meter for any reason, noting that it would support accelerated deployment and help improve the customer experience.[99] Some retailers noted with concern that this provision could force retailers to install meters in situations where there are remediation

99 Submissions to the Directions Paper: PIAC, p. 15; AGL, p. 15; MEA Group, p. 4; Simply Energy, p. 4; EnergyAustralia, p. 2; Essential Energy, p. 2; Ausgrid, p. 4; SAPN, p. 6; Green Metering, P. 10; EDMI, p. 7; Wattwatchers, p. 16; Solar Analytics, p. 7; PLUS ES, p. 22; NECA, p. 6; Department for Energy and Mining, South Australia, p. 5, Secure Meters, p. 8.

issues, no reasonable access, or no business case to the retailer. Retailers recommended that customers be empowered to switch to a retailer that will provide them with a smart meter. This would allow customers to choose a retailer more compatible with their preferences.[100]

C.2.3 Customers should receive smart meter upgrades upon request

The Commission recommends that customers receive a smart meter upon request. An explicit provision to request and receive a smart meter would likely contribute to the NEO by:

- Supporting greater customer choice in product offerings, such as usage data access.
- Improve customer experience by allowing customers to take advantage of tariff options.
- Improve customer satisfaction and experience in meter upgrades, especially where customers themselves have requested an upgrade.
- Would support a more equitable accelerated deployment of smart meters.
- Customers would be more empowered, being able to receive a smart meter should they wish to receive one, regardless of whether their current metering is functional or undertaking a new electricity connection.

C.2.4 Proposed implementation of a provision to request and receive a meter for any reason

This recommendation would be implemented as a new provision in the NERR to explicitly recognise customers' ability to request a meter upgrade for any reason, with the existing timeline requirements in clauses 7.8.10A to 7.8.10C of the NER for customer-initiated requests being applicable. The Commission anticipates this will resolve any issues with customers being refused a smart meter upgrade.

For details on proposed changes to the NERR to enable customers to get a smart meter for any reason, please see amendment number 6 Table C.2.

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?

C.3 Reducing delays in the installation of smart meters

C.3.1 Reducing delays in meter replacement

The Commission considers clear and appropriate timelines for meter replacements need to be in place to support timely meter replacements of malfunctioning meters. The Commission considers that separate timelines for individual and family failures are needed to reflect the different nature of the failures and the resources required by the metering parties to undertake the replacements in each case.

The Commission recommends:

100 Submissions to the Directions Paper: AGL, p. 15; Red Energy and Lumo Energy, p. 4.

- Separating the definition of malfunctions into two categories: 'individually identified malfunctions' and 'malfunctions identified through statistical testing' (family failures).[101]
- The replacement time frame for individual failures and family failures be 15 business days and 70 business days, respectively
- The AEMO exemption process for malfunctions of small customers' type 5 and 6 meters is removed and replaced with circumstances under which time frames for malfunctions will not apply.

C.3.2 Customers are facing delays in the replacement of malfunctioning meters

Under the current arrangements, MCs are required to replace all types of metering malfunctions, regardless of how they are identified, within 15 business days after being informed or within 30 business days if the meter replacement involves interrupting supply to another customer. Where the MC cannot repair or replace the malfunctioning meter within these time frames, they may apply to AEMO for an exemption.

Under the current arrangements, customers face delays in replacing malfunctioning meters, with lengthy time extensions sought under the AEMO exemption framework. Information provided by AEMO indicated that as of August 2021, nearly 349,000 malfunctioning meters had been granted exemptions under AEMO's metering installation malfunction exemption framework. Out of these meters, nearly 246,000 meters were family failures identified through the sample testing process.

C.3.3 Stakeholders generally supported creating two separate categories of malfunctions but suggested a longer time frame for family failures

In the Directions Paper, the Commission recommended setting different time frames for the replacement of individually malfunctioning meters and family failures. The Commission proposed the removal of the exemptions process and a 60-day time frame for family failure replacements.

Many stakeholders, including retailers and metering parties, generally supported creating two categories of malfunctions to improve the replacement process for meter malfunctions.[102] Some of these stakeholders do not support setting a 60-day time frame for family failure replacements and removal of the exemption process.[103]

AGL and PLUS ES view implementing a replacement time frame would be restrictive, and more flexibility is required to allow for a cost-effective and efficient meter replacement as the volume of some family failure fleets can be unpredictable, substantial and inconsistent.[104] Origin, Aurora, and Vector considers the proposed replacement time frame of 60 business days to be unsuitable if a family fleet consists of more than 10,000 meters due to the time,

101 For details on the malfunction categories, see the Directions Paper here www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf#page=92.

102 For details on the proposed changes to the NER for malfunctioning meters, see Directions Paper here: www.aemc.gov.au/sites/default/files/2021-09/EMO0040%20Metering%20Review%20Directions%20paper%20FINAL.pdf#page=44.

103 Submissions to the Directions Paper: CEC, p. 9; Green Metering, p. 11; EDMI, p. 7; Wattwatchers, p. 16; Telstra, p. 2; PLUS ES, p. 23; Vector, 9. 14; Department for Energy and Mining, South Australia, p. 5; PIAC, p. 15; AGL, p. 15; EnergyAustralia, p. 11.

104 Submissions to Directions Paper: AGL, p. 15; PLUS ES, p. 23-24.

field resources and coordination that would be required by metering parties.[105] EnergyAustralia indicates that a 60 business day time frame would only be suitable if the exemption process is retained.[106]

A few stakeholders suggested an alternative replacement time frame to the proposed 60 business day timeframe. AGL and PLUS ES suggested a longer replacement time frame of at least 110 days and 120 business days, respectively.[107] Origin suggested implementing a range of time frames depending on the volume of malfunctioning meters with a family failure fleet (e.g., a replacement time frame of 90 business days for fleets with less than 1,000 malfunctions and 180 business days for fleets up to 10,000).[108]

AGL and EnergyAustralia recommend retaining the malfunctions exemption process if time frames for both categories of malfunctions are to be implemented.[109] Vector supports the removal of the exemption process, indicating that the process does not add value and is burdensome, suggesting it be replaced with a registration process in MSATS.[110]

C.3.4 Individual malfunctioning meters should be replaced in a timely manner

It is important that individual meters that malfunction are replaced promptly, as any delay in replacement could directly impact customer bills and settlements. The Commission considers that the current time frame requirement of 15 business days under NER clause 7.8.10(2) remains appropriate for small customers.

C.3.5 An appropriate replacement time frame requirement for family failures

For family failures, the Commission acknowledges retailer' and metering parties' challenges in replacing potentially many malfunctioning meters within a 15-day time frame under the current framework and considers that a more extended time frame is warranted.

The Commission considers 70 business day provides sufficient time for metering parties to plan and undertake replacement for meters identified through the family failure process.

The proposed changes to the inspection and testing regime mean that the suggested timeline for family failures will be more relevant for smart meters than legacy meters and reflect the longer-term business-as-usual timeline requirements for replacing family failure meters. The 15-business day timeline would continue to be suitable for both smart and legacy meters, as there may still be individual malfunctions of legacy meters, for example, those reported by customers.

C.3.6 There is little value in retaining the exemption process

In light of the proposed changes to the timelines for replacing malfunctioning meters and the inspection and testing requirements for legacy meters (type 5 and 6 meters), the Commission

105 Submissions to Directions Paper: Origin, p. 6; Aurora, p. 4; Vector, p. 16.
106 EnergyAustralia submission to Directions Paper, p. 11.
107 Submission to Directions Paper: AGL, p. 16; PLUS ES, p. 23.
108 Origin submission to Directions Paper, p. 6.
109 Submissions to the Directions Paper: AGL, pp. 15-16; EnergyAustralia, p. 11.
110 Vector submission to Directions Paper, p. 14.

considers there is little value in retaining the exemption process for these meters for small customers. The Commission expects there to be less of a need for exemptions given the extended time frame for replacing family failures and the reduced need for testing legacy meters under a legacy meter retirement plan.

Details on the proposed legal implementation of recommendations to remove the exemptions process are provided in Table C.2 (see amendment 1). Legal changes required to enable other measures, including different timelines, are outlined in the indicative Table C.2.

C.3.7 Implementation

The recommendations for malfunctioning meters would require the following changes to the NER:

- Creating two categories of malfunctions for small customer metering installations, each with different rectification time frames:
  - **Individually identified malfunctions.** The MC must repair or replace meters that have been individually identified as malfunctioning as soon as practicable but no later than 15 business days from when it has been notified. Where the MC has become aware that repairing the meter requires interrupting supply to another customer, 30 business days after the MC has become aware of the need for that interruption unless the site is subject to the multi-occupancy scenario outlined in appendix B.5 of this Report, in which case that framework will apply instead of this clause. This category would cover situations such as:

    — A meter reader reporting that a meter has been physically damaged or the display could no longer be read

    — A metering technician investigating an issue raised by the consumer, retailer (or any party) discovers that components of a smart meter, such as the communication module, need to be replaced.
  - **Malfunctions identified through statistical testing (family failures).** The MC must repair or replace meters that have been deemed to be malfunctioning through sample testings as soon as practicable but no later than 70 business days from when the MC has been notified unless a site is subject to the multi-occupancy scenario outlined in appendix B.5 of this Report, in which case that framework will apply to that site instead of this clause. This category would cover malfunctions generally known as family failures.
- Exceptions would be provided to the time frames where the MC cannot repair or exchange the meter due to issues at the premises, such as defects, safety and access issues. Following the Directions Paper, the Commission's draft position is that the exception for site defect issues would only be available once the MC has followed the proposed end-to-end site remediation process (see Figure B.1). The exceptions would be similar to those in clauses 7.8.10B(b)(2) and 7.8.10B(b)(3) of the NER. The time frame requirement would recommence once the site issues have been resolved.

- MCs would no longer be able to apply to AEMO for an exemption from the time frame requirement for small customers' metering installations.

Adopting different approaches toward testing and inspection arrangements for legacy and smart meters. Testing and inspection would no longer be required where a meter is subject to a Legacy Meter Retirement Plan are in place. The inspection and testing requirements would continue to apply to smart meters.

C.4 Customer risks from automatic reassignment to a new tariff structure

The accelerated deployment of smart meters could facilitate the shift of more customers to cost-reflective pricing structures sooner.

Under the current network tariff framework (appendix C.4.1), DNSPs are increasingly proposing tariff assignment policies that require customers who receive a meter exchange to be reassigned to a default cost-reflective tariff without the ability for retailers to opt-out to legacy tariff arrangements (appendix C.4.2). The AER has set this direction over time to promote network tariff reform. Retailer market offers, which are not regulated by the AER, are increasingly reflecting the underlying network tariff in their market contracts.

Automatic tariff reassignment creates a risk to customers, which can lead to a negative customer experience – as highlighted by stakeholders. Customers may not understand how their usage patterns could impact their electricity bill if they are reassigned to a cost-reflective network tariff. For example, customers who typically heavily consume during peak demand periods may not know the cost impact of this behaviour or are unable to shift their consumption to different times – at least in the short term.

The Commission considers the pricing framework generally fit-for-purpose – it is robust to changing circumstances and customer preferences over time, and provides flexible transitional measures. Nevertheless, the Commission has received strong stakeholder feedback that customer safeguards are required to address uncertainty about how customers will be transitioned to cost-reflective pricing – which is supported by our customer research (appendix C.4.3). The Commission seeks feedback on possible new customer safeguards options to provide greater assurances to customers (appendix C.4.4).

C.4.1 The current pricing framework

The requirement for DNSPs to develop cost-reflective network prices for consumption services was introduced by the Commission's Distribution network pricing arrangement rule change in 2014. In 2021, the Commission made a Rule to enable export charges for distribution services, and allowed for negative prices for consumption and export services.

The NER require DNSPs to develop a tariff structure statement (TSS) that outlines the proposed pricing structure for the next regulatory period – which the AER examines within the distribution revenue determination process.[111] The AER must approve the TSS if it promotes the NEO and meets the specific NER requirements discussed below.[112]

The TSS must comply with the *network pricing objective* and *pricing principles*. The network pricing objective is that a DNSP's tariffs should reflect its efficient costs of providing those services to the retail customer.[113] The pricing principles include 'customer impact principles', such as the requirement for a DNSP to consider the impact on retail customers of tariff changes from the previous regulatory year. Also, the DNSP must have regard to the need for a reasonable period of transition (which may extend over more than one regulatory control period), the extent to which retail customers can choose the tariff to which they are assigned, and the extent to which retail customers can mitigate the impact of changes in tariffs through their decisions about usage of services.[114]

The TSS must set out the policies and procedures the DNSP will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another, the structures for each proposed tariff and the charging parameters for each proposed tariff (among other things).[115]

The NER require DNSPs to describe how they have engaged with retail customers and retailers in developing the proposed TSS, the relevant concerns identified because of that engagement, and how they have sought to address those concerns. Further, the DNSPs' regulatory proposals must describe in reasonably plain language the key risks and benefits for customers of the proposed TSS, which would include customer risks created by the DNSPs' tariff assignment policy.[116]

The DNSPs' TSS consultation provides a forum for retail customers and stakeholders to raise concerns about the proposed policies and procedures for assigning retail customers to tariffs or reassigning retail customers from one tariff to another – including arrangements for mandatory assignment of cost-reflective prices. If a DNSP has not adequately addressed those concerns in its regulatory proposal, stakeholders then have an opportunity to influence the AER's decision on whether to approve the DNSP's proposal. Any person may make a written submission to the AER within its statutory timeframes, and the AER must have regard for those written submissions.[117]

It is up to retailers to reflect network tariff structures in their offers. Retailers pay network charges to DNSPs. Under the current framework, retailers have the discretion to decide how to recover these costs and their other costs as part of their overall retail charges to

111 More information can be found: www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements

112 While the AER's revenue determination sets the total amount of revenue that DNSPs may recover in each regulatory period, tariff structure design is about how this revenue is recovered, not how much revenue should be recovered.

113 NER clause 6.18.5(a).

114 NER clause 6.18.5(h).

115 NER clause 6.18.1A(a). Technically the policies and procedure for assigning consumers to tariff classes are an element of the distribution determination and not part of the TSS. A different test in the NER also applies to this element under NER clause 6.18.4.

116 NER clause 6.8.2.

117 NER clauses 6.10–6.11.

consumers. Retailers are currently free to manage network price signals to customers how they choose as part of their market offers.

C.4.2 What is happening in practice?

The AER has requested changes to most DNSP TSS proposals to date – including to the form of transition as part of the tariff assignment policy and pace of transition. DNSPs have undertaken significant consultation, customer education and consideration of the potential impacts on customers.

As part of the recent network access and pricing rule change process, the Commission engaged an expert consultant to review the implementation of tariff reforms. Farrierswier highlighted several examples of the AER intervening in TSS processes to give greater weight to the customer impact principles.[118] Farrierswier found:[119]

- the existing TSS process and pricing principles provide a range of different transitional tools and other mechanisms that can be used by DNSPs and the AER to mitigate customer impact risks
- there is a high likelihood that scenarios with potential for customer harm would not be proposed by DNSPs or approved by the AER, especially if consumers raise significant concerns with them during the consultation required as part of the TSS process.

Tariff assignment policy was a significant issue for SAPN's 2019–20 regulatory process. In its draft decision, the AER approved SAPN's proposal for the assignment of residential and small business customers with smart (type 4 or 5) meters to the relevant default cost-reflective tariff – without allowing retailers to opt-out of legacy tariff arrangements. However, in the final decision, due to the COVID-19 pandemic, the AER made a decision to introduce transitional arrangements within SAPN's tariff assignment policy for the first year of the regulatory control period. The AER determined SAPN could not automatically re-assign customers to provide:[120]

- retailers with more time to develop new retail products in response to the new network tariff arrangements
- consumers with more time to consider what new retail products might best suit their needs and preferences – noting consumers are likely to favour certainty in the current economic circumstances and consumers' ability to engage with any new and more innovative products may be limited by the impact of the pandemic.

The AER's transitional policy meant:[121]

- residential and small business consumers who are new connections or existing consumers who initiate a change to their connection (e.g., install new solar PV) will be assigned to a

118 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, p. 17

119 Farrierwier, Insights report: Effectiveness of the TSS process and options for implementing export charges, March 2021, pp. 65–66.

120 AER, SAPN Distribution Determination 2020 to 2025, Attachment 18 Tariff structure statement, Final decision, June 2020, pp. 9–10.

121 AER, SAPN Distribution Determination 2020 to 2025, Attachment 18 Tariff structure statement, Final decision, June 2020, pp. 10–11.

cost-reflective network tariff by default, which their retailer may opt-out to a legacy network tariff in the first year only

- residential and small business consumers who receive a smart meter for reasons not instigated by them (e.g., end-of-life replacement), or who received a smart meter before July 2020, will remain on their current legacy network tariff in the first year only, which their retailer may choose to opt-in to the more cost-reflective tariff option.

C.4.3 Stakeholder concerns are supported by the customer research

Newgate Research found a primary barrier to customers requesting a smart meter was time-of-use pricing – many feared the amount they'd pay for electricity would go up with time-of-use pricing:[122]

> Once focus group participants understood that a smart meter would typically mean they would go on a time-of-use tariff, this became their primary cost concern on the basis that this would likely be an ongoing cost while installation would be a one-off fee. While some certainly felt they would be able to change their behaviour and take advantage of this tariff, others were more uncertain and reflected a loss aversion mindset. They wanted evidence that someone in their situation would be no worse off, with some interested in seeing case studies.

Further, Newgate Research found:

- many people adopt quite simple behaviours as their primary way to save energy, but looking forward, many people are interested in saving money by changing how and when they use electricity
- most residential customers adopt a 'wait and see' mindset around innovation in the energy market
- for customers more likely to request installation, the most appealing reason is the potential to save electricity and money, alongside the ease of monitoring usage.

Throughout the Metering Review, the Commission has received feedback on the potential implications for customers being automatically reassigned to a cost-reflective price upon the meter exchange. These stakeholder concerns include that:[123]

- **Customers are forced onto cost-reflective pricing** – Different Rules and jurisdictional policy levels expect the assignment of time-of-use or demand tariffs upon meter exchange.
- **Customers are not informed about whether they would be better off** – Because of the timing of meter exchange and tariff reassignment, customers cannot understand how the meter exchange will impact their bill, for example, how much their previous bill would have cost on a cost-reflective price.

122 Newgate Research Final Report, p. 7.

123 Submissions to the Directions Paper ACOSS et al., pp. 24-26; AGL, p. 19; Alinta, p. 8; Bright Spark, p. 11; CEC, p. 4; ECA, p. 6; Edge Electrons, p. 9; Endeavour, p. 17; Energy Queensland, p. 12; Essential, p. 4; EWON, p. 5; EWOSA, p. 2; ReAmped, p. 1; Red Energy and Lumo Energy, p. 5; Secure meters, p. 9; Simply Energy p. 3; SolarAnalytics, p. 2; Telstra, p. 3; Vector, p. 7

- **Customers cannot choose a different offer or remain on a flat tariff** – Customers are not given a provision to opt-out of a tariff change or be able to choose from a range of different pricing options.
- **Retailers are unaware of the specific network tariff structures** – Local network areas offer different tariff structures, which the retailer only knows after installing a smart meter. In this situation, retailers could wear cost-differential over the installation process.

ACOSS recommends that the Rules should require retailer tariffs to be opt-in upon installation of a smart meter so consumers are not forced onto retail tariffs. ACOSS explains:[124]

> Reforms are needed to prevent consumers being 'opted' in or 'defaulted to' retailer time-of-use and demand tariffs upon installation of a smart meter, which can result in some energy users paying high energy bills. Greater effort is needed to support and educate energy users on how they can benefit from time-of-use or demand tariffs to encourage them to opt-in to these type of retail tariffs.

These above stakeholder views reflect the difficulties experienced in implementing tariff reform in Australia. It requires a significant change management process. Despite some progress at the network level, cost-reflective and socially accepted tariff reform at the consumer level has proven to be difficult to implement. Challenges in analysing the impact on various consumer segments, lack of clarity as to how retailers could optimise network tariffs, how retailers will translate prices to customers, and what protections will be put in place for vulnerable consumers are contributing to concerns and uncertainty.

C.4.4 Options to address customer risks from automatic reassignment to a new tariff structure

The Commission considers the TSS process provides flexibility for DNSPs and the AER to develop pricing structures and tariff assignment policies that meet each DNSP's and jurisdiction's specific circumstances. DNSPs must strongly reflect customers' preferences and stakeholder views in the regulatory proposals and outcomes under the NER. AER discretion and flexibility may be more appropriate in a complex and rapidly changing environment.

Nevertheless, the Commission is considering options for stronger customer safeguards to address concerns about allowing the automatic reassignment of cost-reflective tariffs. The Commission intends to undertake significant consultation on these issues before our final report.

The Commission is considering whether to include more prescriptive requirements in the Rules to address uncertainty about how participants will transition customers to cost-reflective pricing. Options for new customer safeguards include:

1. **Option 1:** Strengthening the customer impact principles under the TSS framework – including prescribing a requirement for DNSPs and the AER to consider the need for additional transitional measures to account for the accelerated deployment of smart meters by amending the existing 'customer impact principles'.[125]

124 ACOSS et al. submission to Directions Paper, p. 8.
125 NER clause 6.18.5(h).

2. **Option 2**: Prescribing a transitional arrangement whereby customers who receive a smart meter within the acceleration period cannot be automatically reassigned to a new retail tariff structure, for example for 12 or 18 months. This will provide customers time to understand their usage patterns, enabled by the more frequent and detailed usage data from smart meters, and make complementary investments to manage better their usage going forward.

Under these options, customers would still be able to consider different market offers and opt-in to retailer services that include a cost-reflective pricing component.

Implementation timing risks with a change to tariff reassignment under an accelerated deployment

There would be practical difficulties in implementing the above changes as part of the New South Wales, Australian Capital Territory, Queensland and South Australian regulatory processes. The New South Wales and Australian Capital Territory DNSPs' must submit their regulatory and TSS proposals by 31 January 2023. These DNSPs will have already undertaken significant consultation processes on their tariff assignment policies. Although there is scope in chapter 6 of the NER to amend a TSS with the AER's approval within the regulatory control period, this would require these DNSPs to undertake further consultation and could complicate aspects of their TSS proposals. DNSP's proposals in Queensland and South Australian DNSPs' are due by 31 January 2024, so there is a limited window to implement any rule changes in time for these DNSPs' TSS proposal consultation processes.

Given the expected timeline of this Review's recommendations and implementation of potential rules, there is a timing risk. The Commission is not aware of other implementation options available to mitigate this potential issue. The AER, relevant DNSPs and the Commission will need to work closely together to clarify expectations for the draft revenue determinations, and minimise uncertainty in the regulatory and engagement processes. Ultimately, the AER can apply its discretion to address these concerns under the existing customer impact principles.

Requiring tariff opt-in arrangements is not being considered by the Commission as an option

The Commission explored an option to prohibit in the Rules DNSP policies to automatically assign customers who receive a smart meter within the acceleration period (2025–2030) to a default cost-reflective tariff. We understood this option may better promote customer choice and trust – and put the onus on the market bodies and industry to demonstrate the benefits to customers of new and innovative access and pricing options.

However, the Commission's initial view is this option is too prescriptive. The TSS process provides a robust consultation mechanism and flexibility to accommodate different network circumstances, customer preferences and government policies – as demonstrated by the above SAPN case study. The regulatory framework should in principle accommodate the potential for jurisdictional differences to advance the NEO. Further, heavily restricting tariff assignment policies would remove the option of a critical mechanism DNSPs and the AER have been applying to progress tariff reform. The AER should continue to balance potential trade-offs in making decisions that, as required, best promote the long term interests of consumers.

The Commission welcomes feedback on this initial position, including any fundamental concerns about the TSS framework – such as whether there is a risk that stakeholder views and consumer preferences of transitional arrangements under the customer impact principles are not being adequately considered by the DNSPs and AER.

It is noted the TSS process only applies to the network tariff. The AER does not regulate retail offers to customers under the current regulatory framework. The Commission welcomes feedback on whether we should further explore with stakeholders measures that could apply at the retail price level to promote better customer outcomes and experiences, and empower customers to more actively choose market offers that best meet their needs.

The Commission recommends complementary measures alongside the potential safeguards

Complementary measures may also be required, regardless of the decision made for tariff reassignment. The Commission recommends strengthening customer information as part of every installation. Retailers will provide information from their retailer that manages expectations to avoid misunderstanding and disappointment, especially regarding tariffs.

In the context of having more time between a meter exchange and tariff structure change, there is scope to provide opportunity and transparency around the tariff process. For example, retailers could demonstrate how a customer's monthly bill on a smart meter with a flat tariff would have compared to a cost-reflective price. In most circumstances, this would show the customer unrealised cost savings.

Complementary measures like this could also lead to the discovery of cost-reflective prices available to the customer to make informed choices on the available services. This allows customers to begin making behavioural changes that lead to meaningful bill savings. Alternatively, some customers could make investments that leverage the change in the meter before their pricing arrangement changes.

Request for stakeholder feedback

The Commission seeks stakeholder views on whether additional customer safeguards are required and, if so, the preferred option. Further, the Commission seeks feedback on how these customer safeguard options could be practically implemented. Different assignment policies could apply to a customer depending on the reason for the meter exchange. For example, a transitional arrangement may not apply to a customer's request as part of a CER installation.

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?

C.5 Legal drafting instructions for potential fast-tracked rule changes

Table C.2: Legal drafting instructions for some draft recommendations

NO.	RELEVANT RULES	PROVISION	DRAFT RECOMMENDATION	THE RATIONALE FOR THE PROPOSED CHANGES
1.	NER	7.8.10	The Commission recommends that the AEMO exemption process for MCs under clause 7.8.10 of the NER is removed for small customers and replaced with circumstances under which the time frames outlined in this clause will not apply. These circumstances would include the site for the meter at the small customer's premises being not accessible or safe or ready for the meter to be installed.	For the policy rationale, see appendix C.3.6.
2.	NERR	59A	The Commission recommends that the number of notices a retailer who proposes to undertake a new meter deployment is required to provide to a small customer under rule 59A is reduced from two notices to one notice. This single notice would be provided to the small customer not	The information required should be aligned with the information requirements under the next row for all types of meter deployment.

NO.	RELE-VANT RULES	PROVI-SION	DRAFT RECOMMENDATION	THE RATIONALE FOR THE PROPOSED CHANGES
			more than 60 business days and not less than 10 business days before the proposed meter installation date.	
3.	NERR	59A	The Commission recommends that the information required to be provided in a notice to a small customer under rule 59A is expanded to include: 1. the reasons for the proposed new meter deployment; 2. how the customer can access their smart meter data; 3. the customer's rights and responsibilities regarding the meter installation; 4. the party the customer should contact to resolve issues, as well as dispute resolution options; 5. any changes to the customer's retail contract resulting from the meter installation, including tariff changes; and 6. a summary of the services available to the small customer as a result of obtaining a smart meter.	The retailer is required to send a smart meter information notice to the customer prior to installation under a retailer-led deployment, except for new connections. The notice should be able to be combined with the PIN.
4.	NERR	59A	The Commission recommends that a small customer's ability to opt-out of the proposed new meter deployment is removed.	For the policy rationale, see appendix B.1.
5.	NER	59C	The Commission recommends that a retailer be required to provide an additional notice to customers under rule 59C when replacing a meter with, or installing, a type 4 or 4A meter. This notice would be provided even if the retailer and small	The proposed additional notice is to account for the types of meter deployments where a notice under 59C is applicable but notice 59 A is not

NO.	RELEVANT RULES	PROVISION	DRAFT RECOMMENDATION	THE RATIONALE FOR THE PROPOSED CHANGES
			customer agreed an interruption time. The additional information would include: • the reasons for the interruption; • the customer's rights and responsibilities regarding the interruption, including any potential costs that may be the responsibility of the small customer; • the party the customer should contact to resolve issues, as well as dispute resolution options; • any changes to the customer's retail contract resulting from the meter installation, including tariff changes; and • a summary of the services available to the small customer as a result of obtaining a smart meter. Retailers would need to provide the information notice at either: • the same time as the notice under rule 59A (if required); or • not more than 60 business days and not less than 10 business days before the proposed meter installation date. To the extent this information is required to be provided by a retailer under another provision of the NERR, at a similar point in time, the Commission proposes that this notice may be taken as satisfying those obligations. The notice would only need to be	applicable. Specifically, for meter deployments that are customer-initiated, a maintenance replacement, replacement of a malfunctioning meter or a programmed deployment.

NO.	RELE-VANT RULES	PROVI-SION	DRAFT RECOMMENDATION	THE RATIONALE FOR THE PROPOSED CHANGES
			provided for the first time a site obtains a type 4 or 4A meter.	
6.	NERR	New provision	The Commission recommends that a new clause is inserted that: 1. enables small customers to request a smart meter from their retailer for any reason; and 2. requires retailers to install a smart meter on receipt of such a request.	For the policy rationale, see appendix C.2.

C.6 Draft comments on other installation issues

Throughout this review, a number of other issues have been raised relating to meter installation which the Commission considers requiring further consideration. In the Directions Paper, the Commission sought feedback on these and any other installation issues which have not been identified in that paper. The issues are:

1. the process for replacing meters following a natural disaster.
2. changes to testing and inspection processes
3. issues outside of the Commission's remit to address.
4. the provision of industry keys to metering parties to enable MPs to access meters
5. what PINs are required for installation situations involving retailers, DNSPs and customer electricians.

C.6.1 Meter replacements following impacts of a natural disaster

The Commission understands there can be significant delays to meter replacements following the impacts of a natural disaster. The Commission considers assistance and cooperation between market participants as described in Rule 94 of the NERR to be particularly important in these circumstances to minimise inconveniences for impacted customers. In addition, in situations where multi-occupancy sites are impacted, the proposed one-in-all-in approach (see appendix B.5.3) could reduce delays and improve the meter replacement process as the approach seeks to address communication and coordination challenges at these sites.

C.6.2 The remaining installation issues will be addressed in the Final Report

The Commission seeks to hold discussions with key stakeholders and address the remaining issues in the Final Report. The one-in-all-in approach intends to address the issue of what PINS are required for installation situations involving retailers, DNSPs and customer electricians. It is an area for further consideration in the development and implementation of the approach (see appendix B.5.3). The Commission welcomes further stakeholder feedback on other installation issues listed above.

D OPPORTUNITIES TO UNLOCK FURTHER BENEFITS FOR CUSTOMERS AND PARTICIPANTS

This appendix outlines the Commission's draft recommendations to enable improved access to smart meter services and data. Stakeholder feedback and the Commission's previous publication identified several challenges and opportunities to promote better outcomes for the market. The key issues identified include a lack of access to power quality data (hereafter referred to as PQD), customers accessing near real-time data, and privacy in data exchange.

BOX 7: DRAFT RECOMMENDATIONS TO ENABLE ACCESS TO SMART METER SERVICES AND DATA

1. Enable DNSPs to access power quality data from MCs.
    a. MCs must provide a new 'basic' data service, including current, voltage, and phase angle, and other data outcomes.
    b. Leaving 'advanced' data services to commercial negotiation, with clearer access rights and Pro-forma processes.
2. Preparing the market for near real-time innovations enabled by a critical mass of smart meters – consumers being able to access real-time data, including potential pathways for:
    a. remote access to near real-time usage data through the retailer.
    b. local access to real-time usage data through the meter.
3. Addressing the potential risk of consumer's privacy concerns.

Feedback is sought from stakeholders on the Commission's proposed approach to address the identified issues and the proposed rule changes to give effect to the draft recommendations.

In addition to these recommendations that unlock further benefits from smart meters, the Commission has considered a future-thinking approach for the future grid that takes a holistic view of technological alternatives to smart meters and the potential economic benefits that consumers will soon realise – the recommendations made in this current appendix are components of a much broader 'ecosystem' (see section 2.2.3).

D.1 Enabling better access to the smart meter's services and data

The Commission recommends that rules be made for PQD access and exchange, including:

- A new definition of "power quality data" be added to NER chapter 10, which would include current, voltage, and power factor.
- New obligations:
    - Enabling DNSPs to procure PQD from MCs under NER 7.15.5.

    - This procurement would be at least once daily; six hourly is preferred (see end of section appendix D.1.2).
    - This procurement would be commercially determined (see appendix D.1.5).
- Requiring MCs to provide DNSPs with access to PQD under NER 7.6.1.
    - This access must include relevant identifiers like NMI number, serial number, and the phase, aligned to market time at the 'basic' level (see appendix D.1.2).
    - This access should also allow for other services to be procured, like Meter inquiry service and Multi-meter ping (see appendix D.1.4).
    - This access should also allow for more 'advanced' PQD services determined by commercial negotiation (see appendix D.1.6).
- By default, accessing parties should communicate PQD directly, invoking NER cl. 7.17.1(f) (see appendix D.1.3).

The Commission has designed this recommendation in three stages:

1. **Establish a 'base case'**: identify the access and exchange arrangement between MCs to provide DNSPs PQD.
2. **Identify gaps**: by recommending a 'base case' arrangement, test support for extending access to all relevant parties (see appendix D.1.7).
3. **Recommending a full-spectrum** data service access and exchange framework if necessary.

This Draft Report covers the first two stages: using the base case of DNSP access to test broader access. The Commission will finalise its position for a potential full-spectrum access framework between the Draft and Final Report based on stakeholder feedback (see appendix D.1.7)

D.1.1 A crucial enabler for smart meter benefits is the access and exchange of power quality data

The Commission's Directions Paper outlined the material issues faced in exchanging PQD, including complexities and costs to negotiate, inconsistent formatting, and price exceeding value to access. In response, stakeholders have provided vital feedback in support of a data access framework to:[126]

- **Enable LV Visibility along with complementary technology solutions:** An access framework is a crucial component of LV Visibility. Stakeholders noted the importance of the scale and location of meters along with other technological solutions, raising implementation risks of costs and duplication of other technology deployments.[127]

126 Submissions to the Directions Paper: AEC, p. 4; Alinta, p. 6-7; Ausgrid, p. 5; Ausnet, p. 2; Bright Spark Power, p. 6; CEC, p. 7; CitiPower, Powercor, United Energy, p. 5; EDMI, p. 5; Endeavour Energy, p. 5; Energy Queensland, p. 15; EnergyAustralia, p. 8; EWON, p. 4; Gridsight, p. 7; Landis+Gyr, p. 7; MEA group, p. 3; NECA p. 4; Origin, p. 5; PLUS ES, p. 15; South Australia DEM, p. 4; Secure, p. 5; SolarAnalytics, p. 5; Vector, p. 10; Wattwatchers, p. 12.

127 Submissions to the Directions Paper: Alinta, p. 6; CEC, p. 6; Edge, p. 14; EDMI, p. 4; Endeavour Energy, p. 11; Energy Queensland, p. 16; EnergyAustralia, p. 7; Green Metering, p. 7; Gridsight, p. 6; Itron, p. 11; Landis+Gyr, p. 6; MEA, p. 6; NECA, p. 4; Origin, p. 5; PLUS ES, p. 12; Secure, p. 5; Vector, pp. 8-9; Wattwatchers, pp. 7-8.

- **Provide standardisation that does not prevent innovation:** Stakeholders noted the breadth of existing standards, guides, and protocols considered in working groups facilitated by the Commission.[128]
- **Support safety outcomes like neutral integrity detection and resolution:** Citipower suggested that a new module could create risk, i.e., false alarms, which can be costly.[129]

This is consistent with the direction of reforms and broadly in line with customer preferences and expectations, based on the evidence the Newgate study provided (see Box 8).

BOX 8: CUSTOMERS SEE VALUE IN SMART METERS PROVIDING MORE BENEFITS: DATA ACCESS IS THE KEY

Respondents to the Newgate Research Final Report study responded positively to smart meters providing outcomes to the energy system, including:

- Smart meters can help identify an area that has lost power — so the network operator can start repairs sooner (75 per cent).
- Smart meters could improve household safety — for example, by reducing the risk of electrocution by detecting electrical faults (74 per cent).
- With a smart meter, customers can access programs that financially reward them for reducing electricity usage for a short period during peak demand periods (e.g., adjusting air conditioning on hot summer days) (72 per cent).
- Widespread smart meter installation can help grid operators plan better and reduce spending on the network infrastructure — which translates to lower electricity bills over the longer term (72 per cent),
- With a smart meter, customers can go on a time-of-use pricing plan (with different prices at peak, off-peak and shoulder periods) — enabling them to shift electricity use to off-peak or shoulder periods when prices are lower and, thereby, reduce customer bills (70 per cent).
- Retailers or a third party with access can use smart meter data to advise customers on different access and pricing options that best meet the customers' needs and preferences (69 per cent).

Following exposure to the features of smart meters, sentiment among residential customers that participated in Newgate's research significantly shifted to be more positive. Small businesses also appear to become more positive towards smart meters.

Source: Newgate Research Final Report, p. 49.

128 Submissions to the Directions Paper: AEMO, p. 4; Bright Spark, p. 6; EDMI, p. 5; Endeavour Energy, p. 5; Energy Queensland, p. 15; EnergyAustralia, p. 8; Gridsight, p. 8; Itron, p. 14; MEA group, p. 3; PLUS ES, p. 15; South Australia DEM, p. 4; SAPN, p. 13; Secure Meters, p. 6; Solar Analytics, pp. 5-6; Wattwatchers, p. 12.

129 Submissions to the Directions Paper: CEC, p. 6; Citipower, Powercor, United Energy, p. 2; Edge, p. 14; EDMI, p. 4; Endeavour Energy, p. 12; Energy Queensland, p. 16; EnergyAustralia, p. 7; Green metering, pp. 5-6; Gridsight, p. 6; Itron, p. 12; Landis+Gyr, p. 6; NECA, p. 4; Origin, p. 5; PLUS ES, p. 12; Secure, p. 5; Vector, p. 8.

Stakeholders also provided strong support for the components of a power quality data access framework, including that it be a combination of two components advised by NERA economic consulting:[130][131]

- A minimum contents requirement.[132]
- An appropriate exchange architecture.[133]

D.1.2 'Basic' power quality data services should be exchanged on a minimum content basis

The Commission's Directions Paper proposed a minimum contents requirement to minimise the complexities of negotiating data and to provide consistency to a 'basic' service's structure, data points, sequencing, and frequency.

Over the Metering Review's pause, the Commission facilitated four Working Group sessions between MCs and DNSPs to establish the 'anchor tenant' for PQD services. Based on this engagement, the Commission recommends that the 'basic' PQD service should:

- allow access to other 'basic' outcomes, like a multi-meter ping and enquiry service (see appendix D.1.4)
- be captured from all communications-enabled Type 4 small customer meters, installed after *Power of Choice*
- be delivered daily at a minimum, every 6 hours (i.e., the prior 72 market intervals) is preferred (see the end of section)
- capture 5-minute data, which is aligned to market time
- identify the meter using the NMI number, serial number, and each element
- record voltage, current, and phase angle (to represent real and reactive power) for exports and imports.

The Commission is satisfied these required minimum contents advance the NEO

To build the minimum content requirement, the Commission used the following principles, which were co-designed with the Working Group:

- Provide a consistent set of measurements and services from all smart meters remotely communicating and be made widely available to DNSPs.
- Basic PQD service is not required from non-communicating smart meters.

130 NERA, Smart Meter Data Access Framework Options, can be found here: https://www.aemc.gov.au/sites/default/files/documents/nera_smart_meter_data_access_framework_options_-_metering_review.pdf

131 The Commission's Directions Paper also contemplated a centralised organisation and a negotiate-arbitrate component which were rejected on the basis of significant implementation costs and material divergence from the long term economic and regulatory trajectory of data services.

132 Submissions to the Directions Paper: AEC, p. 7; Ausgrid, pp. 5-6; AusNet, p. 2; Bright Spark, p. 6; CEC, p. 8; ENA, p. 6; Endeavour Energy, p. 6; Energy Queensland, pp. 19-20; EnergyAustralia, p. 9; Essential Energy, p. 7; Intellihub, p. 11; PLUS ES, p. 19; Red Energy and Lumo Energy, p. 3; SAPN, p. 5; SolarAnalytics, p. 6; TasNetworks, p. 1; Vector, p. 11.

133 Submissions to the Directions Paper: AEC, p. 6; Alinta, p. 6; AusNet Services, p. 2; CEC, p. 9; ENA, pp. 6-7; Endeavour Energy, p. 6; Energy Queensland, pp. 19-20; EnergyAustralia, p. 9; Essential Energy, p. 8; Green Metering, p. 9; Gridsight, p. 9; Intellihub, p. 11; PLUS ES, p. 19; Red Energy and Lumo Energy, p. 3; SAPN, p. 5; TasNetworks, p. 1; Vector, p. 11; Wattwatchers, p. 11.

- Supported by the capabilities of *Power of Choice* meters already deployed and will not require meter hardware upgrades. Upgrade of software and meter reconfiguration may be necessary.
- Available by default to DNSPs from all *Power of Choice* meters at a go-live date in the future.
- As the service will generate large volumes of PQD, the data set should contain essential values only to minimise transaction costs.

These principles support the Commission's recommendation that a minimum content requirement for PQD would promote the NEO. In particular, the costs of standardising the service are likely proportional to the expected benefits of PQD access. These costs are borne by the beneficiary, allowing for recovery of the expenses in the least distortionary way (see appendix D.1.5).

The Commission also believes that prescribing the minimum content required for the 'basic' service would promote the long term interest of consumers by giving predictability and stability to accessing parties, minimising the impacts of regulation and providing a higher chance of success and uptake of PQD services.

In the first instance, 'basic' PQD access will enable power quality monitoring and management strategies that facilitate better maintenance, planning, and operation. With sufficient scale, the Commission sees additional economic benefits toward:

- Calculate grid operational parameters and more accurate dynamic operating envelopes.
- Checking compliance of CER with relevant technical standards.
- Greater participation in wholesale markets.
- Visualising the network and solving losses or constraints, e.g., with distribution-connected batteries.
- Providing passive and procuring active network services.

Feedback and implementation considerations from the Working Group support a minimum contents requirement

Implementation considerations that need to be tested under a full-spectrum access framework raised by the Working Group stakeholders include the need to:

- Differentiate between commercial and industrial large customers with type 4 meters.
- Differentiate between pre-*Power of choice* and non-5-minute settlement type 4 smart meters that are also communications-enabled.
- Allow for the broadest outcomes to be achieved through:
  - Aligning to market time, i.e., to start at 00:00, 00:05, and 00:10.
  - Average versus instantaneous data fields.
  - A naming convention for different labels of phases and elements.
- Define service levels, including:
  - Success rate, e.g., 95 per cent of each day's raw data points.
  - Integrity, e.g., not captured, not sent, not substituted, not estimated.

- Retention, e.g., kept by MC for one week. If data is lost, after one week it is lost.
- Down-time, e.g., outage five per cent of the time expected to be completed within one week.

- Define a data convention that could standardise and raise the veracity of manufacturer recording data – Accuracy of PQD measurements, per patent approval for meter vendors, could be detailed and surmised in a technical specification.

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?
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?

The duration and frequency of the 'basic' power quality data service remain outstanding

An outstanding item from the Working Group was the duration and frequency of the service. DNSPs who participated were asked to vote on two potential duration and frequencies:

- **Option 1 (dubbed 'big bang')**: Data is collected from all meters simultaneously per day. Creates a peak (288 intervals of data) in cost for collection and delivery, but it was noted to be the cheapest for MCs to deliver.
- **Option 2 (dubbed 'progressive')**: Data is collected from all meters in 6-hour blocks (72 intervals of data), providing data sets four times in a 24-hour period. This option was noted to be costlier, but it does provide more benefits (such as a faster detection of supply issues and improved accuracy of state estimators).

DNSPs voted unanimously for Option 2 (the progressive duration and frequency). This was on the proviso that option 2 was net beneficial. The Commission notes that the estimated cost differential between option 1 and option 2 needs further consideration, and the engagement in the working group was inconclusive on the issue of the cost differential between the two options. As noted by various MCs, there are pros and cons from a cost perspective with either option.

Another alternative that was considered valid but rejected. This was a rolling service where PQD would be collected from each meter, once per day, on rotation across the fleet in groups e.g., 1,000,000 meters split into six reading groups of 166,666 meters, each providing 288 intervals of PQ data spread across 6-hourly blocks. It was noted that potentially materially more management would be required to establish reading groups, including capabilities to control groups; however, it would significantly improve LV visibility and provide DNSPs with a data frequency that supports emergent use cases, as a 'basic' service.

D.1.3 'Basic' power quality data services should be exchanged in a standard and agreed-on interface

Utilising the right exchange architecture for the PQD service would provide a standard interface for data exchange. Different platforms can transfer data in predefined formats and utilise partially defined contracts to position parties as close to agreement as possible before exchanging data. This reduces negotiation costs and complexity significantly.

For the 'basic' PQD service at a minimum, the Commission recommends that MCs should exchange with DNSPs along the following parameters:

- The formatting language should be JavaScript Object Notation (JSON).
- The communications protocol should follow the shared market protocol (SMP).
- The route should be directly from peer to peer.[134]

Anything beyond and/or outside these parameters could be considered an 'advanced' PQD service.

Utilising the right exchange architecture for power quality data services is in the long-term interest of consumers

To assess the appropriate exchange architecture to utilise, the Commission used the following principles – which were co-designed with the Working Group:

- Assume that future revisions will be necessary – Emergence of additional use cases in the immediate and longer term. Attempting to anticipate all future use cases will add complexity to the specification without commensurate value.
- Central certificate authority for web service application program interface solution to remain with AEMO.
- Create a minimal specification – A simple interface decreases costs and improves quality.
- Exchange Framework for PQD should work for both 'basic' PQ and 'advanced' PQD services. 'advanced' PQD service means the same data points are delivered more frequently (see appendix D.1.6).
- Focus on core use cases to encourage uptake that will create value across the Australian electricity sector.
- Leverage existing business to business (B2B) standards and patterns as described in the SMP and B2B Technical Guides: The development of a new, stand-alone standard would create an additional burden on all parties and only serve to raise the costs of both growth and maintenance.
- Use existing B2B transactions where transactions are already specified and support use cases. For example, the Meter enquiry service and Multi-meter ping (see appendix D.1.4).

These principles support the Commission's recommendation for a standard and agreed-with exchange architecture for PQD access. A defined route for PQD would improve coordination and reduce complexity in negotiation by bringing all potential parties closer to alignment

134 NER cl. 7.17.1(f) allows parties to communicate data besides the e-Hub but within the B2B procedures. Either the industry would all need to agree not to use the e-Hub for the PQD service in their contracts, or the AEMC could require access based on clause (f).

before transacting. This should reduce the costs of access and increase the potential net benefit of services.

Standardising the formatting language and communications protocol should save time integrating PQD into third-party systems and limit complexity in providing service outcomes. A single, consistent form would reduce transaction costs by avoiding duplication and inconsistencies unless necessary.

Implementation of this recommendation should be resilient to market, technological, policy and other changes. This would contribute to the direction of reform in data exchange – particularly as the industry is moving away from file-based transfers. The Commission expects that this would allow the exchange of PQD to occur within a suitable timeframe to enable the benefits of smart meters relative to realising any costs.

For these reasons, the Commission's recommendations for an exchange architecture are likely to contribute to the long term interest of consumers and promote the NEO.

Feedback and implementation considerations from the Working Group support a standard format outside of the B2B e-Hub

The Commission facilitated a technical Working Group discussion on defining the following parameters of the 'basic' PQD service:

- Formatting language:
  - JSON is the most flexible; however, its compute costs are incrementally greater than alternatives like CSV.
  - The JSON format should work for more 'advanced' services; there is potential for relatively higher conversion rates.
- Protocol:
  - The Commission is aware of alternative platforms, such as *Apache Kafka*, which may not be compatible with the shared market protocol.
  - When the SMP cannot be utilised by default, there would need to be a separate negotiation for a protocol, reducing the benefits of standardisation.
  - DNSPs using an alternative protocol and platform would need to develop an additional new *Representational state transfer* application program interface to receive the SMP.
- Route to exchange PQD:
  - Service-level agreements could influence the ideal route:
    - If exchanging parties wanted independent timestamps, then e-Hub is suited.
    - However, if parties wanted to minimise real-time delay, directly peer-to-peer would be preferable.
  - If e-Hub were to be utilised, AEMC would need to work closer with AEMO to understand magnitude and materiality because:
    - Exchange PQD through the e-Hub may result in further investment by AEMO if the volumes are more material than the current bandwidth.

  - There is a concern that these costs are effectively recovered from all stakeholders.
- Parties could exchange certificates of ostensible authority web services at the contract striking stage of the peer-to-peer exchange.

> 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?

D.1.4 Other services should be procured through the data access framework

The Commission recommends that DNSPs procure additional service outcomes that are latent within smart meters through the access framework. These other services include:

- **Meter inquiry service** – This would adapt the current minimum service specification (e) to provide the 'basic' PQD set from a specified metering installation to the requesting party.
- **Multi-meter ping** – This service is separate from the minimum specification that enables a faster supply restoration via accurate outage location mapping and provides DNSP confirmation of restored supply.

Additional agreement is required between MCs and DNSPs to decide on the proposed parameters (e.g., NMI, service type code, request code/postcode, and response time) required to deliver the expected outcome. The Commission understands that current B2B remote service request transactions can facilitate these outcomes, at least when the AEMC codifies the access framework.

Between the publication of the Draft Report and Final Report, the Commission will engage with relevant stakeholders to determine the best implementation pathway for these additional PQD services, e.g., minimum service specification, industry agreement, or otherwise.

D.1.5 Prices for power quality data services should be determined commercially

The Commission recommends that the discovery of prices for both the 'basic' and 'advanced' PQD services should be commercially determined, and therefore beneficiary pays.

In the 'anchor tenant' scenario, DNSPs would procure a PQD service from MCs as an operational expenditure and recover via distribution use of system charges.

Constraining power quality data services by price may not be proportionate to the potential

benefits

NERA Economic Consulting advised the Commission that, for an access framework to be successful, some key criteria for price discovery were to:[135]

- **Reflect the marginal cost of providing the data** – the marginal value of receiving the data at least exceeds the marginal cost.
- **Ensure the data providers can recover at least their average cost –** this ensures that any fixed costs associated with providing access are spread across all users.
- **Allow for a reasonable level of return** – this is to allow the total benefits of a transaction to be represented in the considerably smaller cost of enabling it.

Direct price control is likely not proportionate to providing access to PQD.

The Commission is aware of implementation issues for price regulation that would have significant additional resourcing implications for the AER. For example, implementation issues may include arbitrating tiered price disputes, establishing and maintaining a benchmark price, and providing oversight for alternative models. These implications are likely disproportionate to the benefit.

The Commission also considers that the significant alignment on standardisation achieved between MCs and DNSPs should mean a marginal difference in prices provided by different MCs. A beneficiary-pays model also allows for innovative commercial models (e.g., a subscription fee plus a small usage fee) or some form of cost-sharing arrangement to cover fixed costs. This should put MCs and DNSPs in the best position to negotiate a price. On balance, even a pricing principle could unreasonably constrain this negotiation of 'basic' PQD exchange.

Alternative pricing models

Besides a beneficiary-pays model or prescribing a price, the Commission has considered alternatives.

One alternative would be codified pricing principles – i.e., *access to PQD must be supplied on a cost-reflective basis* – could better enable access and negotiation and prevent adverse outcomes. NERA provided advice that pricing principles could underpin negotiations to ensure broad benefits of a 'basic' service should realised. Stricter principles would align the internal incentives to transact with the current or potential social costs and benefits.[136]

Besides this, an alternative model would be for the MC to provide 'basic' PQD to DNSPs at no cost. This is similar in principle to metering data requirements for settlement data. These costs of business are recovered through the retailer and metering coordinator annuity. The advantage of this approach would be the competition of procurement costs between retailers and MCs, rather than negotiating prices between DNSPs and MCs.

Stakeholder views may have shifted as the power quality data service has become more

135 NERA, Smart Meter Data Access Framework Options, Final, p. 17.

136 NERA, Smart Meter Data Access Framework Options, Final, pp. 17-18.

defined

Stakeholder engagement with the Commission's consultation paper raised market power issues in data access. The Commission's Directions Paper acknowledged that:

- Negotiation costs are material and can offer perverse incentives to either 'hold out' or bypass the meter.
- Restrictive commercial arrangements, e.g., contractual agreements between parties can explicitly deny access or exchange between market participants.
- Current data prices demanded by metering parties exceed the likely marginal cost of providing the data.
- Prices can vary significantly between data providers for the same request (i.e., a similar amount of meters, the volume of data, and the time frame).

The Commission sought stakeholder views on options for some form of regulated pricing to enable the exchange of data, including a negotiate-arbitrate model. Options ranged from tier-based pricing or benchmarking to alternative value-based or cost-floor pricing models. In response to the Directions Paper, stakeholders had said:[137]

- An access framework should not force prices.
- Costs to achieve the outcome are likely to exceed the benefit of access.
- Pricing could be beneficial as a countervailing power, if at all, for more discretionary data.

> 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?

D.1.6 'Advanced' power quality data services should be left to commercial negotiations

The Commission's Directions Paper outlined the complexities and costs of negotiating access. This was based on stakeholders' low certainty and alignment on the market demand for, and authority to provide, metering data.

The Commission and interested stakeholders have significantly reduced the difference between potential access parties and service providers. The agreement has been reached on the following (see appendix D.1.2):

- The format, frequency, and delivery mechanism.
- Providing ongoing access and certainty.
- Placing mutual obligations on market participants.

137 Submission to the Directions Paper: Alinta, p. 8; Ausgrid, pp. 5-6; AusNet, p. 3; CEC, p. 9; Endeavour Energy, p. 6; Energy Queensland, p. 19; Essential Energy, p. 8; Green Metering, p. 9; Gridsight, p. 9; Itron, p. 16; PLUS ES, p. 19; Red Energy and Lumo Energy, p. 3; SAPN, p. 5; Vector, p. 11.

NERA Economic Consulting provided advice that access frameworks usually divide outcomes by tiers. For example, Tier 1 has stricter requirements due to high and broad system benefits, while Tier 3 has fewer requirements due to more private and bespoke benefits.[138]

The Commission considers that an access framework to PQD should be separated across two levels: 'basic' and 'advanced.' Based on the engagement undertaken between the Working Group, an 'advanced' service would reasonably capture the following:

- higher resolution or sampling volume
- more frequent delivery, such as near real-time data
- other 'advanced' services
- other data points, like the supply frequency (Hertz)
- potentially a different endpoint or bespoke architecture.

The Commission considers that this reasonably captures the potential PQD services the market may require without causing obligations to be captured and sent by default. An access party would have the right to request and receive an 'advanced' PQD service based on the Pro-forma 'basic' PQD standard.

These 'advanced' PQD services would include substantial fixed set-up costs due to the potential for designing a bespoke exchange architecture and the likely higher operating costs than the 'basic' service. Commercial negotiation is best placed to derive access because access parties will only pursue the 'advanced' service if the benefits outweigh the costs.

D.1.7 After seeing the proposed 'base case' for power quality data, who else should have access?

The Commission's intention with the PQD access framework in this Review is to test who else could be given a right to access the PQD service besides the DNSP. While the bulk of the benefits is specific to the DNSP, the Commission believes that the list of potential access parties suggested by stakeholders could be given access (see Table D.1).[139]

A full-spectrum access framework is ideal; however, the Commission requires further feedback on implementation considerations

The Commission believes an access framework should be neutral to potential access parties – its implementation would be simple enough not to impede the likely uptake or success of the framework, considering the roles of market participants and consumers. A neutral access framework would also minimise the impacts across different energy and related market segments and promote dynamic efficiency.

138 NERA, Smart Meter Data Access Framework Options, Final, pp. 17-18.

139 Submissions to the Directions Paper: AGL, p. 10; CEC, p. 7; EDMI, p. 5; Energy Queensland, p. 15; EnergyAustralia, p. 8; Gridsight, p. 7; Itron, p. 14; Landis+Gyr, p. 7; NECA p. 4; PLUS ES, p. 15; Secure, p. 6; SolarAnalytics, p. 5; Tesla, p. 1; Vector, p. 10; Wattwatchers, p. 12.

Table D.1: **Potential for a neutral access framework for power quality data services**

POTENTIAL ACCESS PARTIES	POTENTIAL SERVICE/BENEFITS	POTENTIAL IMPLICATIONS
• AEMO and the AER. • Behind-the-meter service providers. • Customers and their devices. • Energy consultants. • OEMs. • Research institutions. • Retailers and traders.	• Checking compliance with local network assets. • Flexibility services, like small generation aggregators. • Monitoring CER system performance. • Providing active network support services. • Usage and power system analysis. • Validating the operational performance of the network.	• Basic format and frequency are suitable. • Non-DNSPs would pay for this service. • How non-market participants could receive access directly from peer to peer. • Services that have not been discussed may be demanded as a 'basic' service. • The SMP is applicable for non-market participants. • Certain metering-related data, such as unique identifiers like NMI numbers, can't be shared with non-DNSPs.

Some potential impacts exist in providing access to non-DNSPs. On balance, these potential implications are solvable. For example, leaving the 'advanced' service relatively open could satisfy any likely demand that a non-DNSP may have (see appendix D.1.6); or whether non-DNSPs could suffice without personal identifiers (see appendix D.1.2).

The Commission welcomes stakeholder feedback on how material these implications, and their resolution, could be relative to their potential benefit.

D.2 Preparing the market for near real-time usage data innovations enabled by a critical mass of smart meters

The Commission is considering whether it could make regulatory changes to prepare the market for innovations closer to real-time data[140] that a critical mass of smart meters would otherwise enable in the long term.

The Commission could make changes to enable customer access to a (near) real-time data stream sooner than the market would offer because this outcome is among the most

140 By near real-time data, the Commission considers access to be every five minutes. Real-time data, therefore, would be less than five minutes and as close to instantaneous as possible.

persuasive and credible drivers of the shift in sentiment toward smart meters in customers interviewed by Newgate Research Final Report.[141] The Commission's draft position includes:

Table D.2: Preparing the market for near real-time usage data innovations enabled by a critical mass of smart meters

Service outcome	Consumers able to access real-time usage data	
Service pathway	Remote access	Local access

Considerations	Options include:
	1. Near Real-time remote access by default
	2. Opt-in to a near real-time remote service
	3. Promote partnerships between retailers and new entrants.
		• Defining a customer's right to access the smart meter for specific purposes, i.e., real-time data stream.
		• Defining a technical standard for:
		  ◦ Read-only formatting: the port provides "raw" data almost instantaneously, relating to the smart meter's data objects, which cannot be changed.
		  ◦ Uni-directional communications: the user cannot communicate back through the port to the meter.
		• Processes for activating, deactivating, and consenting to a local real-time stream.

D.2.1 Overarching service outcome: Consumers able to access real-time usage data

Part of the benefits of a critical mass of smart meters is to enable new and innovative services to be developed or provided more efficiently. The research undertaken by Newgate

141 Newgate Research Final Report, p. 50.

found that, of the total sample, 74 per cent of customers responded positively to the statement:[142]

> Smart meters allow people to check their usage in dollars in real-time so you can budget more effectively and avoid surprises at bill time

This finding was the third-highest net positive response, with the highest being:[143]

> Smart meters mean you receive accurate bills based on your actual real-time usage – there are no more estimated bills

Based on the evidence and the Commission's understanding of the current breadth of service offerings, current access levels may not be sufficient for emergent reforms, such as demand-side flexibility and dynamic operating envelopes.

Under these emergent reforms, customers may require data directly at a high enough frequency to shift demand or achieve energy savings. Simply, this could include a load curve updated in near real-time via a phone app (see Box 9). This real-time service could eventually include a customer's authorised representative or someone the customer has consented to access the real-time data, e.g., a customer energy management system (CEMS) or authorised service provider behind the meter.

The Commission considers it valid and feasible to enable the innovation of this overarching service outcome, through two potential service pathways, as its consistent with the relevant trends for the future grid, namely, participant's digitisation strategies.

D.2.2 Potential service pathway one: Remote access to near real-time usage data

For consumers to be able to access real-time usage data from their smart meter, one potential service pathway would be remote access. Remote access would be the more common service pathway, in which the customer could receive a near real-time stream of data via their smartphone app or devices in the home. Ideally this would be a 'bring your own device' outcome, which is emerging in today's market, but changes to the regulatory framework could further enable it, sooner.

From submissions to the Directions Paper, the Commission recognises that there is a significant stakeholder split regarding consumer demand for and the ability to provide near real-time usage data:

- Consumer demand for billing data is being met, and retailers are prevented from innovating a near-real-time service, which some stakeholders attribute to the themes of:[144]
  - **Costs**: Material costs are associated with large-scale systems, apps, and portals.

142 Newgate Research Final Report, p. 49.

143 Newgate Research Final Report, p. 49.

144 Submissions to the Directions Paper: AEC, p. 4; AGL, p. 11; Alinta, p. 7; Aurora, p. 3; Bright Spark, p. 6; Energy Queensland, p. 16; EnergyAustralia, p. 8; Itron, p. 14; Origin, pp. 5-6.

- **Customer engagement**: Consumer responsiveness is still developing. Making new use cases will not lead to more significant benefits.
- **Low demand**: Some stakeholders said no evidence suggests that customers are dissatisfied today or need more timely access to other data.
- **Equity concerns**: Making changes would only benefit a few customers at the expense of the broader customer base.

- The current framework is not delivering long-term value to customers, which some stakeholders attribute to the themes of:[145]
  - **Complexity**: access and accessibility are not customer friendly.
  - **Timeliness**: access is not timely enough to reasonably change user behaviour.
  - **Incentives**: retailers and DNSPs have no reason to utilise this data or partner to give access—especially to a third party.
  - **Consumer segments and preferences**: most consumers need guidance to understand and respond to these data capably, but some more informed "prosumers" can maximise their utility through services they value.

BOX 9: ON DATA VALIDATION

Part of the cost and timeliness issues outlined above are due to the high validation bar that usage data must undergo for settlement.

Currently, smart meters are being read for billing purposes at least once a day. Validation of consumption data can take up to two business days to complete. These limitations present a gap in what could be considered both 'real-time' and 'validated.'

Customers need data to be captured and structured instantaneously for these real-time use cases. Timeliness is more important than processing and validation because the customer is not making billing decisions but adjusting consumption behaviours or automatically optimising behind-the-meter generation and load.

Retailers should be able to provide a real-time unvalidated service because it is necessarily different from the standard of a monthly billing process. This includes:

- Limiting a real-time service to essential values, like kilowatts, only.
- Metering data provision procedures could be updated to allow for more real-time access to smart meter data
- Providing customers with some disclaimer or warning on the live data stream that it is subject to validation like 'estimated' bill forecasts do today.

145 Submissions to the Directions Paper: ACOSS+, p. 9; CEC, p. 8; EDMI, p. 5; Endeavour Energy, p. 5; EWON, p. 4; EWOQ, p. 1; Gridsight, p. 8; PLUS ES, p. 15; Rheem, p. 7; Secure, p. 6; SolarAnalytics, p. 6; Wattwatchers, p. 12.

Short-term measures could better enable the expected long-term service outcome

The Commission considers that new regulatory instruments should be developed to manage different stakeholder concerns. Noting the costs, the Commission has not received estimates on the potential financial impact of the investment in information technology and communication required to better enable the expected long-term service outcome — stakeholders are invited to provide commercial information on a confidential basis where possible. The Commission expects these costs are non-zero, however, in the absence of that information is assumed to be less than the potential value of the service.

The Commission would like to engage on three potential options to enable innovation in remote access to near-real-time data:

- **Option 1: Requiring near real-time data be provided to customers in specific services.** Customers and their representatives will likely require timely and symmetrical data for future use cases, like demand-side flexibility and network support services.
  - Customers could receive additional benefits from participating in new specific services like aggregation, demand response, or dynamic operating envelopes if their data is presented in an accessible and customer-friendly way, such as instantaneously visualised in a portal or an app.
  - Under this scenario, customers would be allowed to opt-out of receiving the near real-time stream, such as if it is too complex or their preferences change. This could benefit customers that the Commission would consider as 'early adopters' or are already highly engaged.
  - This has the additional benefit of bringing forward some incremental costs associated with large-scale real-time systems that retailers would incur when building the new energy service or otherwise eventually. The Commission understands that these costs are non-zero, however, does not believe they are in excess of the value — especially when these costs are likely to have already been made.
  - The Commission acknowledges a need to explore further the data customers want access to and can benefit from being communicated in these new use cases. Intrinsically, customers want to know how much energy they consume at which time.
- **Option 2: Allowing all customers to opt into a near-real-time retail service**: customers who see a benefit in intra-day consumption monitoring could opt into a near-real-time service – matching unmet consumer demand with a service.
  - Principally, this could work the same as optional extras, e.g., carbon offsets. An opt-in model could contribute significantly to building the consumer engagement and responsiveness required for the future grid.
  - The Commission understands that smart meters are technically capable of this outcome; however, retailers and MCs do not turn on the service and backend by default. This option would require a conversation between the customer and their retailer, then the retailer and their MC to turn on the service. This menu of options should provide better outcomes to the broader consumers, to take control of their energy usage and optimise their consumption..

    - Repurposing the metering data provision procedures and associated rules could facilitate this, i.e., establish minimum requirements for the manner and form in which near-real-time metering data should be provided. E.g., a customer requests a metering data provision that the retailer authorises the MC to provide via either the retail app or portal provided by the MC.
- **Option 3: Promoting cooperation and partnerships with new entrants to provide specialised and unique services:** retailers could accommodate data-specific service providers by forming partnerships to lead innovative near real-time streaming services.
    - Alongside the new and replacement smart meter deployment, other monitoring and management devices are facing similar incentive-based and segmented customer issues, which pose material difficulties for unauthorised firms' commercial models despite their rate of innovation.
    - There is a latent opportunity to match competition incentives and consumer access with firms' ability to cooperate. Partnerships between retailers and unauthorised service providers could earn customer engagement and scale specialised services without impacting the competitive landscape.
    - These partnerships could be trialled and tested in a regulatory sandbox.

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?

D.2.3 Potential service pathway two: Local access to real-time usage data

Following the publication of the Draft Report, the Commission would like to engage with interested stakeholders on whether local access is beneficial and, if so, whether it is possible to overcome the material barriers, including:

- Defining a customer's right in accessing the smart meter locally for specific purposes, e.g., real-time data access.
- A technical specification to outline:
  - **Read-only formatting**: the port provides "raw" data almost instantaneously, relating to the smart meters' data objects, which cannot be changed.
  - **Uni-directional communications**: the user cannot communicate back through the port to the meter.
- Processes for activating, deactivating, and consenting to a local real-time stream.

The second-best approach would be for a customer or their authorised representative to receive a real-time remote service under the metering installation inquiry service. As identified below by the CEC this could be defined under the minimum service specifications; however, service-level parameters around remote requests and delivery would require additional clarification between parties.

Local access to near real-time data currently has material complexities but presents significant potential benefits

Some customers could benefit from accessing near real-time meter data under an AEMO Integrated System Plan *Step Change* scenario. The broader utility of this outcome is likely to be maximised by assigning this access to a third-party service provider, like an authorised representative. With this, customers and their agents would be able to:

- optimise CER asset life, performance, and compliance
- orchestrate behind-the-meter
- respond to emerging network services like dynamic operating envelopes.

As detailed by the ESB's interoperability Directions Paper:[146]

> …[CEMS] providers can make use of real time meter data where meters provide an appropriately accessible local data sharing port. This is separate to permissioned access that may be provided via the meter providers' cloud. Local meter data sharing can reduce the cost of consumer energy resources deployment by reducing the need for separate monitoring hardware.

When parties cannot get access, there are circumstances where parties install additional metering and monitoring. This can present a significant and inefficient impost on consumer's installations.

The Commission understands that local access would be the first-best approach for a near real-time engineering data use case. An Ethernet port or an additional adaptor must be available for real-time and local access to smart meter data. The Commission understands that current arrangements present three highly prohibitive issues:

- Not all meters have local access ports or meter board spaces.

146 ESB Interoperability policy Directions Paper, p. 22.

- Smart meters with ports can only be removed and/or resealed by a qualified electrician who is often not the behind-the-meter service provider or metering party. This creates a time and material issue for a service to begin.
- Under the current rules, the customer does not have the right to access the ports or hardware inside their meter – to prevent tampering.

In the CEC's submission to the Commission upon the restart of the Metering Review, it said:

> The NER's Table S7.5.1.1 Minimum Services Specification – services and access parties states that the small customer can authorise a remote (part e) "Metering installation inquiry service" and that data is time-stamped beyond energy data (i.e., voltage, current etc) but the data comes via the metering coordinator cloud and there is no option of accessing the data in real time by interfacing with the meter itself.

The request description specifically says a "remote" request. There is no mandated timing for the delivery of the cloud data, and it could arrive days later.

Under the proposal by the CEC, the Commission would likely need to make changes to define 'local access' to the smart meter ports, potentially under the minimum service specification (e). CEC's proposal would likely require additional procedures around the technical standards and security protocols necessary to exchange that data locally.

Additionally, the Commission would likely need a process around activating or deactivating the local access port – a material complexity today:

- Metering coordinators are responsible for the metering installation and data but do not have a relationship with the customer.
- The customer's retailer owns the relationship between the metering installation and the customer.
- For the customer to have local access granted and activated, they would have to receive consent from the metering coordinator via the retailer to activate the port remotely (unless the customer could contact the MC directly).

Consumers would realise a material benefit by integrating the real-time stream with CER or CEMS. The Commission considers there to be additional complexity in situations where the customers would want to engage a third-party service provider to receive this local access service via CER or a consumer energy management system. In particular, the current rules do not contemplate a near real-time stream or how a customer's agent could carry out this work.

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 access 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?

D.3 Addressing customer's concerns about privacy

Unaddressed privacy concerns could undermine customers' willingness to accept an accelerated deployment and embrace new and innovative services. The Commission considers that recommendations could strengthen the energy rules or national privacy framework to address these customer concerns — to promote trust and confidence in outcomes enabled by an accelerated deployment.

D.3.1 '*How personal data will be used*' was the second most significant concern for consumers in the Newgate study

After seeing the features of smart meters, a quarter of customers in the Newgate study expressed concern or asked a question about smart meters, with privacy being the second most significant concern.[147]

Customers need to have trust and confidence that data exchange observes and protects their privacy – especially under an accelerated deployment, exposing more customers to the potential impost of being concerned for their privacy. Through the process of earning trust and confidence from customers, the industry should commit to ongoing evaluation. The maintenance of trust should mitigate potential risks and promote the (re)gaining of social licence.

Considering the recent data breach in the telecommunications sector, the Commission understands the potential for increased concern about secure access to personal data and how participants will use personal data – customer's concerns may be heightened for privacy and security.

D.3.2 Options for consideration

In assessing the materiality of this risk, the Commission has utilised the ESB's Consumer Risk Assessment tool.[148] If data privacy under an accelerated deployment presents:

1. **Severe consequences and a high likelihood to occur:** the market bodies could act to strengthen existing requirements on market participants, or it could influence actions

147 Newgate Research Final Report, p. 62.

148 Final advice to ministers, part C, ESB https://esb-post2025-market-design.aemc.gov.au/32572/1629945838-post-2025-market-design-final-advice-to-energy-ministers-part-c.pdf#page=26

by jurisdictions or the Australian Competition and Consumer Commission to address the risk.

2. **Moderate consequences or moderate likelihood to occur**: the Commission could draw a clearer link between the information transparency measures recommended in this report (see appendix C.1) and the current privacy framework principles. Market participants could communicate the terms and conditions of their privacy policies in consumer-friendly language.
3. **Low consequences and/or not yet imminent:** the risk would benefit from ongoing observation.

At this stage, the Commission does not consider strengthening existing requirements on market participants to be proportional to the risk. The Commission does not consider market participants are in breach of, or their practices are misaligned with, existing consumer data protections. The Commission strongly supports the current privacy principles and their commitment to ongoing evaluation.[149] In addition to compliance with the national privacy framework, significant civil penalty provisions currently cover such obligations.

In gaining and maintaining a social licence, market participants should earn customer's trust that participants use their data in their best interests — this is a space where the industry can always do more. It is vital that consumers receive information on how the current framework protects their personal data, especially their retailer's compliance with the national privacy principles and relevant privacy policies. This could be facilitated through the new information provision (see appendix C.1.1) that retailers would provide in all installation scenarios.

In addition to improving information transparency, the Commission could support the Privacy Act by actively observing the general risk for privacy concerns throughout the accelerated deployment. The Commission would rely on specific delivery chains across jurisdictions, such as ombudsman schemes. The Commission also does receive direct correspondence from consumers who have inquiries about the energy rules, which the Commission could observe for privacy-related concerns.

The Commission welcomes feedback on the extent to which stakeholders agree there are currently gaps in, or a need to strengthen, the national privacy framework and rules — including whether the Commission should recommend additional safeguards commensurate with the risk.

149 More information can be found here: www.oaic.gov.au/privacy/australian-privacy-principles

E REFORMS UNDERWAY THAT RELY ON A CRITICAL MASS OF SMART METERS

Combining and aligning reforms underway is necessary to deliver better consumer outcomes. The Commission's Metering Review recommendations must and should support the reform programs currently preparing the market for a highly digital and consumer-first future.

Many market reforms depend on interactions with each other to succeed – as much as possible, the Commission doesn't want to consider metering recommendations in isolation. Instead, the Commission's preference is to enable successful outcomes of other reforms as much as possible by accelerating the smart meter deployment.

Market reforms incorporating mutually reinforcing outcomes and providing avenues to address specific issues within the national framework are crucial to promoting consumers' ability to actively participate in the NEM through their smart meters, as outlined below. The timely deployment of smart meters is a critical enabler for this forward work program.

E.1 Energy Security Board — Post-2025 Market Design

The ESB published its final advice to Energy Ministers on the Post-2025 Market Design in July 2021. The ESB's reform pathways for integration of CER and flexible demand rely on the metering framework for the timely deployment of smart meters. As PIAC submitted, "reforms to the energy market post-2025 will require advanced metering."[150]

These reform programs seek to benefit households and businesses through the most efficient integration of rooftop solar PV, battery storage, smart appliances and other resources. Customers can benefit from using their CER resources to provide demand flexibility, network support services, and participate in wholesale energy and system services markets. These reform opportunities improve the return on customers' investments in CER and can help all customers, even those without CER, by lowering the electricity system's costs.

The ESB's work outlined how clarifying different metering options in the NER will help to make it easier for customers with CER to participate in the wholesale market and other markets via a retailer or aggregator. The ESB has considered additional ways for new retailers and aggregators to enter the market and provide different choices to customers.

Further, ESB's reform design support innovation in wholesale market arrangements and provides DNSPs with the ability to accommodate the continued uptake of CER and manage network security, and AEMO with visibility and tools to operate a safe, secure and reliable system.

E.1.1 The ESB's Data Strategy

The post-2025 market requires greater access to data. As part of the Data Strategy, the ESB stated that metering provides a potentially vital data source to increase the visibility of

150 PIAC, submission to Directions Paper, p. 8.

network loading. The ESB identified a range of opportunities for retailers, customers, and networks, to leverage meter data better.[151] The ESB considered that data from meters is underutilised and can benefit consumers, retailers, DNSPs and others if market bodies address issues with access and incentives.

The ESB considered that the Commission's Review should address areas including: metering data access rights for DNSPs; voltage reporting; CER minimum metering requirements; opportunities to accelerate the uptake of competitive metering to assist LV visibility; and updated metering requirements to ensure consumers are getting optimal value in terms of LV visibility and wider CER integration. [152]

The initial reforms of the ESB Data Strategy are focused on the broad challenges public bodies face with sharing energy data between themselves and with other public interest bodies: its complex, has stringent assessments to overcome, and is constrained by privacy concerns.

In the medium and longer-term reforms, the ESB will be providing recommendations for:

- **Network transparency data** – which would create an efficient path to the shared network data needed to optimise CER and inform decisions of CER providers, consumers, and regulators.
- **Over-voltage data** – which would aim to support efficient investment in network monitoring and voltage management system.
- **EV Visibility data** – which would ensure agencies and market participants have sufficient visibility of emerging EV technologies to support efficient and responsive forecasting, planning, and operational management.

E.1.2 ESB and DEIP's progress in behind-the-meter interoperability, including interoperable access

Interoperability should be standardised to allow data portability and sharing between consumers, aggregators, networks, and the market operator. Consumers' CER assets should have a level of portability between providers. These standardised communications should enable consumers to move between providers (and technology) and promote competition between providers.

The ESB recently published a directions paper seeking feedback on the implementation of interoperability.[153] The ESB mentions metering parties' requirements under the metrology procedures and market ancillary service specification, while also suggesting use cases in interoperability between CER, including where CEMS providers can make use of real-time meter data where meters provide an appropriately accessible local data sharing port. This is separate from sanctioned access that may be provided via the meter providers' cloud. Local meter data sharing can reduce the cost of CER deployment by reducing the need for separate monitoring hardware.

151 ESB, Data strategy final recommendations, July 2021, p. 26.

152 ESB, Data Strategy Consultation Paper, October 2020, p. 125.

153 ESB, Interoperability policy Directions Paper, October 2022, see here: [1665556228-interoperability-policy-directions-paper-final.pdf (datocms-assets.com)]

As well, for seeking interoperability between DNSPs and market participants, it was seen as crucial for metering parties to transmit voltage and other data to inform network state estimations and for dynamic operating envelope compliance verification.

A key source of customer and market data will be the smart meter in the future distribution network. The Commission considers that future recommendations on the implementation of CER interoperability standards should consider the inclusion of the smart meter wherever possible so that communication pathways to access service and data outcomes are dependable.

E.1.3 The ESB's consideration of roles and responsibilities in a post-2025 market

The ESB's CER Implementation Plan supports change with technical and process reform through evolved roles and responsibilities that market reforms will introduce for traders (aggregators/retailers), distribution networks, and the system and market operator.

The ESB is utilising known and expected use cases; these include dynamic operating envelopes, flexible trading arrangements, and new energy products and service packages. The ESB has been engaging with a stakeholder working group on defining the functions, known responsible parties, and how or when the activity should be performed.

The Commission anticipates that current and future reforms will benefit from greater clarity on roles and responsibilities in these use cases, especially in identifying potential gaps. To this end, the Commission believes that the Metering Review's recommendations should be consistent with these actions.

E.2 AEMO's proposal to introduce flexible trading arrangements

Following an ESB recommendation, AEMO's May 2022 proposed a rule change to implement flexible trading arrangements (FTA) for CER. The idea of FTA is to enable end users to separate their controllable electrical resources and independently manage them from their passive load without needing to establish a second connection point to the distribution network. AEMO says its proposal offers consumers:[154]

> ... more flexibility and new opportunities to benefit from innovative products and services that create value, increase competition, and expand choice around how they manage and engage with their [CER]. More broadly, by enabling consumers to be rewarded for their flexibility without needing to change their on-demand energy use, [FTA] is expected to support the transition towards a two-sided market, more efficient integration of CER into the electricity system, and enhanced market outcomes for consumer.

A more fully developed two-sided market with FTA enabling greater participation on the demand side of the market would rely on sufficiently capable smart metering. The Commission will need to consider the merits of AEMO's proposal carefully. Regardless of our

154 EMO, Electricity Rule Change Proposal: Flexible trading arrangements and metering of minor energy flows in the NEM, May 2022, p. 1 (cover letter).

decision, the Commission expects similar reform opportunities – that rely on smart meters – will be raised coming out of upcoming ESB processes.

E.3 AEMO and DISER's Cybersecurity framework

The digitalised and decentralised electricity network will require sufficient cybersecurity standards and strategies to protect essential infrastructure. Cyber vulnerabilities and threats will increase as the distribution network becomes more open and interconnected – through both platforms, application programme interfaces, and more hardware.

These key considerations drove AEMO to establish the AESCSF and uplift cybersecurity across the energy sector, co-led by DISER. [155] Accordingly, the Commission considers that the cybersecurity framework sufficiently covers the potential and emerging cyber risks and supports the AESCSF's ongoing assessment.

E.4 Work being undertaken by jurisdictions

E.4.1 Queensland Energy and Jobs Plan

The Commission would like to recognise the Queensland Government's recent Energy and Jobs Plan that will target 100 per cent uptake of smart meter devices with appropriate data-sharing arrangements by 2030 by leveraging reforms by the Commission and other jurisdictional levers.[156] The Department of Energy and Public Works and Energy Queensland will lead this work – whom the Commission will work closely with on implementation.

E.4.2 Promoting innovation for New South Wales energy customers

The Commission would also like to recognise the New South Wales Government's current consultation of reforms to improve customer access to and uptake of new energy technologies and innovation, including progressing the deployment of smart meters. The Commission will endeavour to facilitate coordination with the New South Wales Government in their consideration of:[157]

- Meter costs to customers – including how the costs and benefits of smart meter installations are currently communicated to customers, and whether customers should be provided with information on the cost of installing a smart meter.
- Meter life and redundancy charges – including the need both to mandate a retirement age of basic meters and for the AER to reconsider the depreciation approach for unrecovered meter assets in the next round of electricity distribution regulatory resets.
- Solar connection delays – including the current allocation of responsibilities within metering and the coordination of planned interruption notifications as significant barriers to installing smart meters on time.

155 See AESCSF here: aemo.com.au/en/initiatives/major-programs/cyber-security/aescsf-framework-and-resources

156 More information can be found here: www.epw.qld.gov.au/energyandjobsplan/about

157 NSW Government, Promoting innovation for NSW energy customers, Public consultation paper, December 2021, pp. 4–11. More information can be found here: www.energy.nsw.gov.au/nsw-plans-and-progress/public-consultations/energy-customer-policy-reform#key-documents

E.4.3 Consumer Data Right in Energy

The Commonwealth Treasury conducted a strategic assessment of the economy-wide deployment of the Consumer Data Right (CDR). The CDR is a significant, economy-wide reform designed to empower consumers to benefit from the data Australian businesses hold about them and in doing so strengthen competition, innovation and productivity.[158]

In November 2021, rules and laws were made that implement the CDR in the energy sector.[159] Product data will be available from October 2022 to provide consumers with better information about energy products and service offerings and support more detailed comparison services, followed by phase one of consumer data from November 2022.[160]

From 15 November 2022, consumers can access their historical usage data through the CDR in energy. The CDR in energy aims to allow consumers to access their historical meter data. A consumer should be able to get data for a meter even if they have changed retailers while associated with the same meter. Consumers will not be able to get data for meters they are no longer associated with (e.g., they have moved house). The goals of CDR are focused on things like encouraging product comparisons and switching and cross-sectoral use cases (e.g., packaging of energy products with banking and telecommunications products).

The Commission is confident that the recent implementation of the CDR in energy can provide consumers with a historical data set, including their billing and tariff data. Consumers can choose accredited providers to share their CDR data with and receive timely and convenient services. The Commission will continue to work with the Commonwealth Treasury through the launch of the CDR on 15 November to support its utilisation.

158 The Australian Government the Treasury, Implementation of an economy-wide Consumer Data Right, Strategic Assessment, Consultation Paper, 2021, p. 6. More information can be found here:treasury.gov.au/consumer-data-right/energy-sector-consumer-data-right

159 More information can be found here: https://www.legislation.gov.au/Details/F2022C00187

160 The Australian Government the Treasury, Strategic Assessment: Outcomes, January 2022, p. 2.

F ECONOMIC ASSESSMENT OF ACCELERATED DEPLOYMENT

The Commission engaged an independent expert consultant, Oakley Greenwood, to undertake an economic cost–benefit assessment of accelerating the deployment of smart meters across the NEM (excluding Victoria and Tasmania).[161] The assessment considered the economic costs and benefits of this setting compared to the status quo of replacing legacy meters on a 'new and replacement' basis (section F.1).[162] Oakley Greenwood's report is published along with this draft report and can be accessed here [placeholder for link].

This appendix outlines the key findings of the Oakley Greenwood assessment (appendix F.1) and further details on the underlying assumptions (appendix F.2) used for the study.

F.1 Summary of the Oakley Greenwood cost-benefit analysis results

Oakley Greenwood found the overall benefits of an accelerated deployment are greater than the costs (in Net Present Value (NPV) terms, 2022) for **New South Wales and the Australian Capital Territory ($256 million)**, **Queensland ($197 million)** and **South Australia ($53.7 million)**.[163]

Oakley Greenwood's modelling results show an accelerated deployment targeting 2030 would result in benefits to consumers through:

- **Avoided manual meter reading costs**, including the avoided costs of manual meter reads – i.e., scheduled reads and special reads – and remote disconnections and reconnections. In NPV terms (2022), New South Wales and the Australian Capital Territory can achieve benefits of $136 million, Queensland of $48.3 million and South Australia of $35.6 million.
  - These network activities are experiencing diminishing economies as smart meters are gradually deployment under the current metering framework. For example, meter readers are increasingly skipping houses with smart meters, which means the travel distance between jobs increases – raising the average reading cost (time taken) per house. An accelerated deployment speeds up the winding down these network activities and, thereby, reduces the overall costs to customers.
  - Data for these network costs was taken from the relevant DNSPs' most current Regulatory Information Notices (which are audited and require CEO sign-off).
- **Achievement of significant economies of scale** from installing meters by geographical area, rather than the current ad hoc deployment. Oakley Greenwood finds that the achievement of economies of scale more than offset the costs brought forward under an accelerated deployment in New South Wales and the Australian Capital Territory

161 Victoria previously mandated the deployment of smart meters. Tasmania more recently mandated that all accumulation meters are to be replaced by 2026.

162 As compared to the current 'new and replacement' policy in which smart meters are installed when an accumulation meter fails, or when a new meter is needed due to new construction or significant renovation.

163 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 3.

(total benefit of $7.18 million) and Queensland (total benefit of $20.8 million), but not in South Australia (total cost of 10.3 million).

- South Australia does not achieve the same level of benefits as the other jurisdictions because SAPN's reported meter read and remote disconnection costs are lower than the other jurisdictions.
- The expected reduction in installation costs from a more streamlined, geographically concentrated deployment was based on evidence from the mandated, DNSP-led Victorian deployment.

- **Enable customers to benefit from the take-up of new pricing options such as 'solar soaker' sooner**. This, and the incentives that new pricing options could provide for Electric Vehicle (EV) charging to be shifted to the daytime, can lead to benefits to customers in New South Wales and Australian Capital Territory of $110 million, Queensland of $126 million and South Australia of $25.9 million.
  - 'Solar soaker' tariffs that allow households to consume and (for some) charge their electric vehicles (EVs) in the middle of the day at very low or zero cost has seen significant customer and stakeholder support across jurisdictions. Oakley Greenwood's modelling only assumed a modest uptake of these tariffs. There is potential for greater benefits if more customers take up the new tariff options and change their usage patterns.
  - In addition to solar soaker tariffs, Oakley Greenwood modelled critical peak demand tariffs – which enable reduced network and generation augmentation costs attributable to peak demands, and reduced generation dispatch costs (during peak periods).[164] Oakley Greenwood assumes a limited uptake of these tariffs.
  - Oakley Greenwood assumed EV customers would go on an EV tariff that helps to shift a significant majority (two-thirds) of EV charging to the daytime.
  - The benefits of tariff reform are lower in South Australia because SAPN's recent regulatory proposal applied a significantly lower 'long-run marginal cost' estimate compared to the other jurisdictions.
- **Enable quicker restorations**, with benefits to customers of $2.64 million in New South Wales and Australian Capital Territory, $1.70 million in Queensland and $2.62 million in South Australia. More efficient identification of the location/source of outages leads to lower emergency response costs.
  - Oakley Greenwood assumed a maximum improvement in restoration times of 5 per cent, which can be achieved with a uptake of 80 per cent of smart meters.

As discussed in more detail below, Oakley Greenwood assumed the bring forward of information technology (IT) costs is unlikely to be material, and says it is likely that the capital costs for developing systems to process interval data have primarily been made. To the extent that there are additional costs, Oakley Greenwood considers there are likely to be

164 In its report, Oakley Greenwood states "the magnitude of the impact on peak demand will depend in part on how EVs are assumed to be managed under the BAU case (i.e., are they 'unconstrained', with EV owners relying predominately on 'convenience' charging, or are they 'managed' / 'incentivised' by way of interruptible tariffs, not requiring a [smart meter]" (p. 36)

offsetting cost reductions due to not having to operate and maintain their accumulation metering and related IT systems.[165]

Oakley Greenwood's full report provides a more detailed breakdown of the benefits and costs including by jurisdiction.

F.1.1 Sensitivity analysis

Oakley Greenwood notes the cost-benefit analysis remains positive even when solar soaker tariffs and price signals to EVs are excluded.[166]

Oakley Greenwood used a weighted average cost of capital (WACC) of 5 per cent. If a 7 per cent WACC is used, the results decline but are still positive.

Oakley Greenwood also modelled the completion of the accelerated deployment program by 2032. It found the benefits to consumers remains positive but lower than if the acceleration is completed by 2030.

F.1.2 Timing of costs and benefits

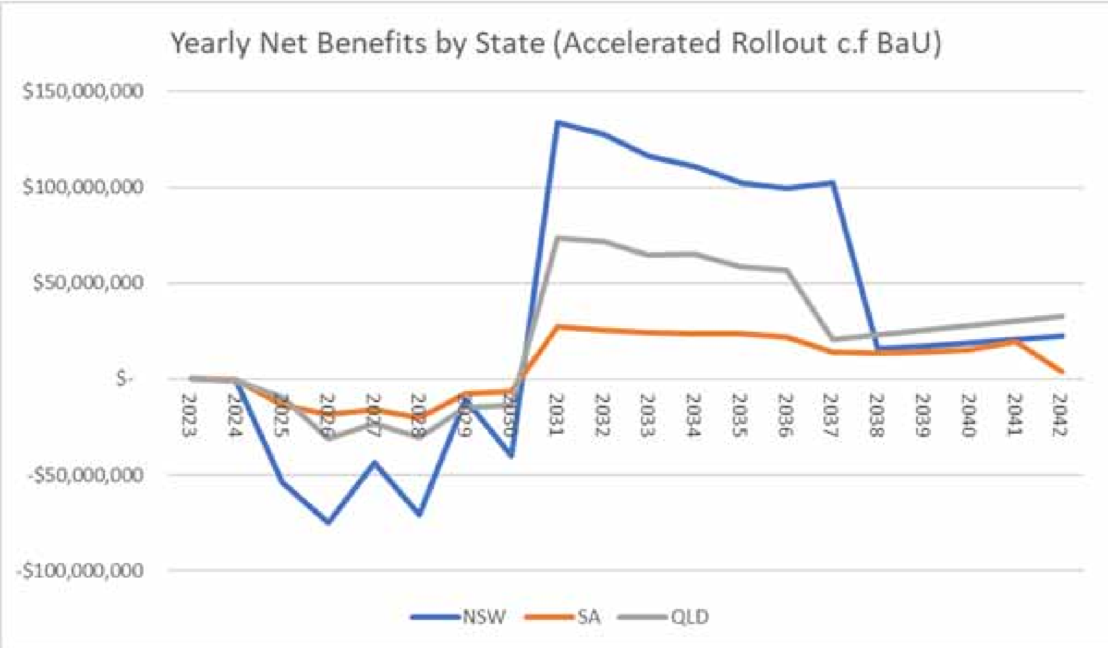
The Oakley Greenwood assessment modelled how the net benefits of accelerated deployment vary over the timeline of the analysis period. It found that initially, net benefits were negative over the acceleration period until 2030, after which there would be significant net benefits accrued as depicted in the figure below.[167] The study highlighted the potential for short-term cost impacts for customers.

165 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 47.

166 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 26.

167 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 18.

Figure F.1: Net benefits profile of accelerated deployment



Source: Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 18.

The net benefits profile observed can be explained as follows:

- The net benefits decline in the early years because more costs (e.g. meter installation and capital costs) are incurred earlier under the accelerated deployment than BAU.
- Once completing the accelerated deployment program, net benefits accrue year-on-year. This results from having more smart meters installed, allowing more remote reading of meters, and the DNSPs avoiding the capital and install costs they would have otherwise incurred under the BAU case in those later years.
- The benefits drop off later, reflecting when each jurisdiction would complete its BAU deployment.

Understanding the financial implications

The Oakley Greenwood assessment was undertaken as an economic costs and benefits analysis, and it did not assess the financial impacts of acceleration. The Commission notes that the accelerated deployment will carry financial implications for parties involved in metering, which could impact customers.

The Commission considers that the net benefits timeline outlined above — which provides a system-wide perspective — does not directly translate into the financial costs and savings that will be seen by customers and retailers. However, there could be short-term cost impacts for customers under accelerated deployment. These issue is further discussed in appendix F

F.2 Oakley Greenwood's key assumptions

The study compared the costs and benefits accrued under the deployment of smart meters under the current new and replacement arrangements to a scenario where the deployment of smart meters is accelerated to achieve universal uptake by 2030.

Oakley Greenwood assumed that the capital costs of deploying smart meters will not be avoided as the current framework envisages legacy meters to be replaced under the 'business-as-usual' (BAU) scenario. The commencement of the accelerated deployment is assumed to start in 2025 and installation levels reach their peak midway through the accelerated deployment timeframe.

Oakley Greenwood started with AEMO's 2022 Integrated System Plan (ISP) forecast of annual PV (Step Change scenario) uptake to estimate the impact of the uptake of PV. Customers with a solar system are assumed to receive a smart meter under the BAU deployment, so accelerating the deployment is not assumed to affect these customers.

F.2.1 Benefit assumptions

Oakley Greenwood did not model all the benefits that smart meters can provide and focus on the major costs associated with an accelerated deployment. This narrower assessment is designed to draw on robust and available data, and minimise assumptions to establish a core business case for the accelerated deployment.

Oakley Greenwood identified the following incremental benefits associated with acceleration:

- **Lower meter installation costs:** the costs of installing smart meters were forecast to be lower under acceleration as programmed deployment would enable greater economies of scale to be achieved in meter installations.
- **Lower meter reading costs:** the costs associated with meter reading and special meter reads will be avoided under acceleration as universal uptake will be achieved at an earlier date and the losses of economies of scales in meter reading would be avoided and reduced.
- **Reduction in network costs:** potential reductions in electricity supply costs due to the ability for DNSPs to apply more cost-reflective tariffs.
- **Lower reconnect and disconnect costs:** reconnection and disconnection costs would be avoided through earlier use of remote reconnections and disconnection.
- **Quicker restoration benefits:** under acceleration, customers would be able to benefit from quicker restoration of outages from an earlier date

Oakley Greenwood identified 19 other benefits from the accelerated deployment of smart meters that were not quantified but were understood to be small relative to those highlighted above, (based on a 2010 study).[168]

168 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 1; 49.

Oakley Greenwood stated additional contingent, but difficult to quantify, benefits are possible from the accelerated deployment of smart meters – including more real-time data and access to apps, and other dynamic, innovation benefits.[169]

F.2.2 Cost assumptions

Oakley Greenwood identified the following incremental costs associated with acceleration:

- **Meter capital costs:** Meter capital costs were found to be higher under acceleration as these costs would be incurred earlier time under acceleration than under BAU.
- **Implementation costs:** The assessment considered there would be costs to implement the acceleration program that wouldn't be experienced under BAU

Oakley Greenwood used a WACC of 5 per cent and a modelling period of 20 years.

Oakley Greenwood considered that the deployment timeframe should not lead to significant resourcing issues for metering providers.

To account for meter failure/replacement, the age profile of each DNSP's non-smart meter fleet was established based on information provided by the businesses to the Commission. The replaced accumulation meters are assumed to have no economic value (i.e., no scrap value).

IT cost assumptions

Oakley Greenwood did not include retailer and DNSP IT costs in its modelling.[170] It assumed that the 'bring forward' of IT costs is unlikely to be overly material, in the context of the overall cost–benefit analysis.

First, Oakley Greenwood assumed it is likely that the capital costs for the development of systems to process interval data have largely been made. Oakley Greenwood stated retailers and DNSPs:

- should be aware that under the new and replacement policy, smart meter numbers will grow over time and ultimately constitute the entire meter stock
- will already be dealing with a certain proportion of their customers having smart meters and therefore will have undertaken billing/settlement system development to manage this data

Also, Oakley Greenwood considered the advent of 5-minute settlement will have been another development that would have likely required these parties to undertake IT system development, and that AEMO have almost certainly built systems to accommodate 5-minute settlement.

Second, Oakley Greenwood considered bringing forward the number of smart meters in the market may theoretically increase the speed at which existing systems (primarily for data storage and processing) reach capacity. However, Oakley Greenwood stated DNSPs are likely

169 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, p. 1; 49.

170 Oakley Greenwood, Costs and Benefits of Accelerating the deployment of Smart Meters, September 2022, pp. 47–48.

to have built these systems in advance of their forecast uptake of smart meters over their next regulatory period to achieve economies of scale.

Third, Oakley Greenwood considered there are likely to be offsetting cost reductions as a result of not having to operate/maintain their accumulation metering and related IT systems.

G ADDRESSING SHORT-TERM COST IMPACTS

As discussed in appendix F, the Commission engaged an independent consultant Oakley Greenwood to conduct an economic cost-benefit analysis of accelerating the deployment of smart meters in the NEM. Oakley Greenwood found that accelerating the deployment of smart meters would deliver significant benefits over a 20-year period.

Oakley Greenwood's analysis also shows that while there are net benefits over the long term, there would be short-term economic cost as future investments are brought forward which could result in short-term cost impacts.

This appendix sets out the Commission's consideration of the cost impact of accelerating smart meter deployment on retailers and customers.

Stakeholders are concerned the timing of the benefits of smart meters will not necessarily match when the investment costs are incurred (appendix G.1). The financial interactions between metering providers, retailers and customers can be complicated, and the AER does not regulate retail offers to customers – including how they recover their various costs.

The Commission considers current industry practice to smooth the upfront metering costs, and socialise these costs across the entire customer base, is likely to continue (appendix G.2) and retailers will benefit from offsetting cost savings (appendix G.3). Further, new customer safeguards will create greater transparency to increase the risk to retailers of customer churn (appendix G.4).

The Commission welcomes stakeholder feedback on the residual risk to customers of short-term bill impacts, and whether additional safeguards should be considered (appendix G.5).

G.1 Concerns about the short-term impacts on customers of accelerated deployment

Metering costs consist of the cost of the device and its installation (capital cost) and costs involved in the provision of metering services (operating costs). For smart meters, operating costs cover services such as routine maintenance (for example, software or firmware updates) and the collection, storage and transfer of metering data. For legacy meters, the majority of the operating costs are for meter reading.

As a result of the accelerated deployment of smart meters, retailers are likely to face higher metering costs overall in the short term compared to a system with legacy meters. As highlighted in the AER's latest Default Market Offer, the per-unit annual costs for legacy meters are generally lower than smart meters. The cost difference is largely due to the limited services and functionality provided by legacy meters, and the capital costs of legacy meters have largely been recovered due to their age. For meters where the capital costs have not been fully recovered, retailers also need to continue paying the capital recovery charge until the end of the meters' capital life.

Without acceleration, the total metering costs faced by retailers were expected to grow gradually in line with the proportion of customers with smart meters. However, accelerated deployment will lead to a faster increase in the proportion of customers with smart meters. This, in turn, would lead to retailers facing an increase in total metering costs and hence their input costs to service customers from an earlier time. This issue was highlighted by some stakeholders in their submissions to the Directions Paper.[171]

Given the potential for retailers to face increased costs in the short term, some retailers may seek to pass on higher metering-related costs to customers. They may seek to pass on the costs either through higher ongoing costs or as a one-off charge at the time of meter replacement.

G.2 Retailers are expected to smooth the cost increases for customers

The Commission has considered current industry practices of how metering coordinators charge retailers for their provision of metering services, and how retailers pass those costs through to consumers.

Retailers can incur two types of metering costs: smart meter annuities paid to the metering providers for their customers with smart meters and legacy meter charges for their customers with legacy meters. Under current industry practice, retailers do not generally pay for smart meter installation and capital costs upfront for small customers at the time of installation. Rather, retailers face an annualised charge that cover both the capital and operating costs of smart meters. For legacy meters, retailers pay DNSPs ongoing legacy metering charges comprised of capital and meter reading costs.

The Commission understands that the majority of retailers recover their total metering costs from across the customer base rather than charging a higher fee for customers with smart meters. Most retailers also tend to recover metering costs as part of the customers' overall retail plan rather than through one-off up-front charges.

As a result, customers generally pay for metering as part of their overall retail plan.[172] Metering costs, like other input costs for retailers, do not appear as a separate line item on customers' bills.

The Commission expects that the current industry practices for the recovery of metering costs will continue under accelerated deployment. This smoothed cost profile should be passed through to consumers. Further, we consider the approach of retailers recovering metering costs through their customer base is appropriate given all customers benefit from the accelerated smart meter program, as highlighted by the cost–benefit analysis undertaken by Oakley Greenwood (appendix F).

171 Submissions to the Directions paper: ActewAGL, p. 1; AEC, p. 7; Endeavour Energy, pp. 4, 10; Red/Lumo Energy, p. 4; Simply Energy, p. 2; Tango, p. 3; CEC, p. 5; ReAmped, p. 1; Origin, pp. 1,2,4; ACOSS, p. 7; PIAC, p. 9; Essential Energy, p. 6; Edge Electrons, p. 6, 23; QFF, p. 2.

172 Some retailers do charge some up-front costs such as legacy meter displacement fee, or minor remediation costs.

G.3 Offsetting short-term cost reductions

In the Commission's view, the accelerated deployment of smart meters will deliver several benefits to DNSPs and retailers, which should flow through to customers in the short term and offset the cost impact of bringing forward the new meter payments.

First, metering parties' installation costs (per unit) are likely to be reduced due to the greater efficiencies achieved from replacing meters by geographical area at a greater scale. This, in turn, is likely to reduce the annuities for smart meters – assuming these efficiencies are passed through by the metering providers.

Second, under acceleration, retailers will realise significant cost savings sooner. Retailers will no longer require DNSPs to provide remote re-energisation and de-energisation and meter reading services.

It is noted that the DNSPs in New South Wales the Australian Capital Territory and Tasmania are likely to have started their next regulatory control period by the time any rule changes are made to require the accelerated rollout of smart meters. The Commission needs to further consider several possible implications, including the potential risk that the expected short- and long-term network cost savings will not be fully passed through to consumers under the regulatory framework.

G.4 Transparency measures create a competitive discipline on retailers

As part of the package of reforms to facilitate faster deployment of smart meters, the Commission has proposed enhanced information provisions as a safeguard for customers as outlined in section C.1.1.

Under these measures, retailers would be required to inform customers about any upfront costs and any changes to the customers' retail offering such as increased retail charges, associated with the metering upgrade. This would mean that if a retailer chooses to levy significant upfront costs for metering or significantly higher retail charges, then customers would receive upfront information regarding it. Competition in the retail market should mean that some retailers may have retailer offers that do not include an upfront fee or provide a lower cost offer, and customers would be able to switch their retailer and receive a better offer.

G.5 Request for stakeholder feedback

Despite the above offsetting and mitigating factors, there is a residual risk that customers may face an increase in their electricity bills before the longer-term benefits are realised.

The Commission seeks feedback from stakeholders on its understanding of the above issues – including whether the mitigating factors would provide sufficient protection for customers from potential short-term negative cost impacts, or whether additional safeguards are required.

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?
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?

H QUESTIONS TO RECOMMENDATIONS

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?

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 time frame 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?

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?

QUESTION 4: RETAILER TARGET (OPTION 3)

1. Do stakeholders consider option 2 is feasible and appropriate for accelerating the deployment of smart meters? Are there aspects of option 2 that need further consideration?
2. If this option is adopted, what are stakeholders' suggestion 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?

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?

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?

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?

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?

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 time frames 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 time frames?
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?

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?
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?

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?

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?

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?
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?

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?

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?

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?

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 access 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?

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?
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?